Capacity Market Structure Review

Issue Discovery Report - Final

A Report by the
New York Independent System Operator

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Acronyms

Abbreviation or Acronym	Description
CMSR	Capacity Market Structure Review
NYISO	New York Independent System Operator
ICAP	Installed Capacity
CLCPA	Climate Leadership and Community Protection Act
DCR	Demand Curve Reset
CONE	Cost of New Entry
EAS	Energy and Ancillary Services
LOLE	Loss of Load Expectation
NYCA	New York Control Area
LSE	Load Serving Entity
UCAP	Unforced Capacity
MW	Megawatt
CARC	Capacity Accreditation Resource Class
CAF	Capacity Accreditation Factor
NYSRC	New York State Reliability Council
LI	Long Island
ROS	Rest of State
CFD	Contract for Difference
MMU	Market Monitoring Unit
MRI	Marginal Reliability Improvement
TSL	Transmission Security Limit

LCR	Locational Installed Capacity Requirement
IRM	Installed Reserve Margin
CLMP	Capacity Locational Marginal Pricing
VOLL	Value of Lost Load
NPCC	Northeast Power Coordinating Council
FCM	Forward Capacity Market
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
NREL	National Renewable Energy Laboratory
EIA	Energy Information Administration
SCGT	Simple Cycle Gas Turbine
NERA	NERA Economic Consulting
FERC	Federal Energy Regulatory Commission
ZCP	Zero Crossing Point
MP	Market Participant
UDR	Unforced Capacity Deliverability Rights
EDR	External-to-Rest of State Deliverability Rights
WSR	Winter-to-Summer Ratio
SWR	Summer-to-Winter Ratio
NCZ	New Capacity Zone
SDU	System Deliverability Upgrade
EUE	Expected Unserved Energy

Executive Summary

The New York Independent System Operator (NYISO) launched the Capacity Market Structure Review (CMSR) project to evaluate whether its Installed Capacity (ICAP) market remains effective in delivering reliable, transparent, and economically efficient outcomes amid evolving grid conditions. Through time, the ICAP market has successfully supported resource adequacy by incentivizing efficient market entry, exit, and retention. The ICAP market provides a transparent market signal for the value of resource adequacy. However, the evolution of the New York grid is accelerating rapidly. Electrification, increased integration of intermittent renewable resources, and emerging seasonal reliability risks have prompted a reassessment of the ICAP market's design fundamentals. The passage of the Climate Leadership and Community Protection Act (CLCPA) introduced additional considerations on how the wholesale markets interface with energy policy to efficiently provide grid reliability. The CMSR project provides a mechanism to chart a path forward for the NYISO's ICAP market design.

Evolving the ICAP market first requires an understanding and alignment of the objectives of the CMSR project. The objectives developed are as follows:

1. Identify market structures that will help facilitate New York's evolving grid consistent with policy goals and achieve the following objectives:
    a. accurately value resources according to their contribution to maintaining bulk system reliability;
    b. deliver transparent and predictable market outcomes;
    c. operate cohesively with the Energy and Ancillary Services markets to meet the reliability requirements of the evolving grid;
    d. provide appropriate, non-discriminatory, price signals to existing and new resources;
    e. function without unnecessary administrative complexity; and
    f. provide an economically efficient, durable, and stable market structure to facilitate investment.
2. Explore potential alternatives to the existing structure.
3. Determine if the existing structure or alternatives explored better meet the defined objectives.

Through the CMSR project's extensive stakeholder engagement, the NYISO has identified five priority areas for future development: ICAP Demand Curve Reset (DCR) Process and Methodology Improvements, Winter Reliability Capacity Enhancements, Reliability Attribute-Based Capacity Pricing, Capacity Zone Redesign, and Improving Capacity Accreditation and Resource Adequacy Modeling. These priorities reflect the NYISO's strategic focus on improving the valuation of locational and operational reliability attributes, addressing the growing importance of winter reliability, and reducing administrative complexity,

The ICAP DCR Process and Methodology Improvements project is a priority due to the timing of the ICAP Demand Curve's quadrennial reset cycle. Completing market design improvements in advance of the DCR will allow thorough and careful consideration of this important process. As part of this project, the NYISO proposes modifying the shape and slope of ICAP Demand Curves to better reflect marginal reliability improvements, thereby enhancing price stability and investment signals. The NYISO also aims to stabilize ICAP market outcomes by potentially refining proxy unit definitions, exploring the appropriateness of long-run gross Cost of New Entry (CONE) estimates, and exploring alternative approaches to net Energy and Ancillary Services revenue offsets.

The Winter Reliability Capacity Enhancements project addresses the shift toward near-term winter reliability risks that are projected to increase over the long-term as the grid transitions to a winter-peaking system. The NYISO proposes establishing seasonal New York Control Area (NYCA) Minimum ICAP requirements, seasonal Transmission Security Limit (TSL) floor values, and seasonal Locational Minimum Installed Capacity Requirements (LCRs); seasonal elections for Unforced Capacity Deliverability Rights (UDRs) and External-to-Rest of State Deliverability Rights (EDRs) with a Must Offer Requirement; and adjusting the ICAP Demand Curves to reflect the development of seasonal NYCA Minimum ICAP Requirements. These proposed changes are designed with the aim that the ICAP market continue to send appropriate signals for winter preparedness and resource adequacy.

The Reliability Attribute-Based Capacity Pricing project seeks to align market incentives with the evolving reliability needs of the grid. By explicitly compensating resources for attributes that address reliability needs such as transmission security and exploring signals for dispatchability, fuel assurance, and cold-weather performance, the NYISO aims to support investment in technologies that enhance system resilience. This initiative merges concepts from valuing transmission security and an attribute-based market design, offering a framework for considering additional reliability attributes in the future.

The Capacity Zone Redesign effort seeks to improve the locational accuracy of capacity pricing. The NYISO proposes reviewing zone boundaries, sub-zonal granularity, and dynamic transmission constraints. These market design elements may improve price formation, support efficient investment decisions, and align market outcomes with physical system realities. Importantly, more granular zones may support efficient deliverability assessments when new resources interconnect.

Finally, the Improving Capacity Accreditation and Resource Adequacy Modeling project aims to increase transparency and visibility into the resource adequacy models. This project will explore adjustments to marginal capacity and resource adequacy modeling that may improve ICAP market stability, enhance transparency, and support more informed decision-making by market participants. Reducing the complexity of these models may increase the predictability of market outcomes and facilitate economically efficient investments. Adjustments could include, but are not limited to, adopting an alternative marginal capacity accreditation calculation, utilizing additional historical input data into the resource adequacy model, and further refining the LCR setting process.

In conclusion, the CMSR project has reaffirmed the foundational strength of the NYISO's ICAP market while identifying targeted enhancements for its continued effectiveness. By prioritizing efforts that reduce complexity, reflect seasonal and locational reliability needs, and align market signals with system value, the NYISO is positioning its ICAP market to meet the challenges of a dynamic and evolving grid. These initiatives will guide the NYISO market design efforts through the next decade, ensuring that the ICAP market remains a robust tool for maintaining reliability, supporting investment, and delivering value to consumers.

Introduction

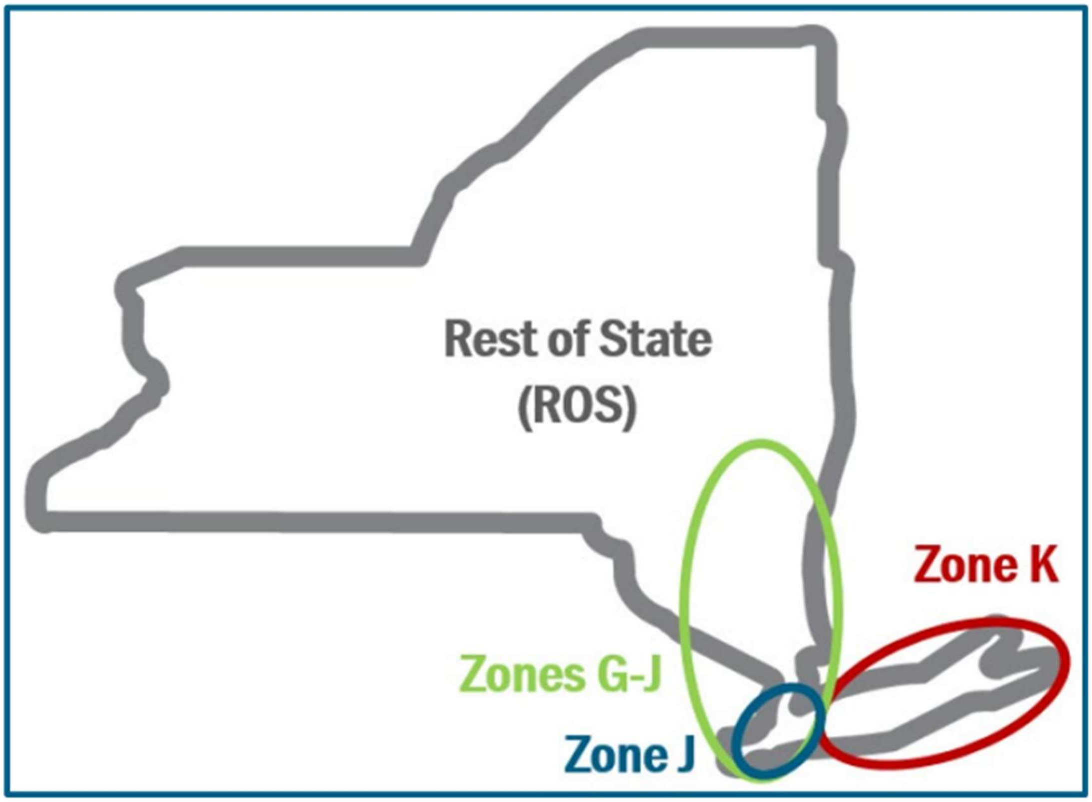
In conjunction with the NYISO's Energy and Ancillary Services markets, the NYISO's ICAP market provides incentives to market participants in New York to have the right mix of resources to maintain bulk system reliability at an efficient and effective level for consumers. The ICAP market has accomplished this objective by providing appropriate price signals to incentivize efficient market entry, exit, and retention. ICAP market price signals have formed the bedrock of capital investment in New York. The ability for market participants to effectively forecast future market clearing prices, based on transparent market administration combined with their own assumptions, provides stable foundations for revenue projections. These signals drive decisions for reinvestment in current resources and are the basis for bilateral agreements, offtake agreements, hedges, and power purchase agreements to facilitate the construction of new supply resources. More recently, these signals have been the foundation for New York State contracts awarded to build out the technologies needed to meet the goals of the CLCPA. However, as the needs of the electric system and the drivers of investment have evolved, a review of the structure of the ICAP market is warranted to evaluate the market's ability to continue to provide appropriate price signals to maintain bulk system reliability at an efficient and effective level for consumers. In 2024, NYISO stakeholders urged the NYISO to take a comprehensive look at its ICAP market to confirm that the foundational structure is sound and consider what changes, if any, may be required (summarized in more detail below). The NYISO identified ICAP market challenges and ideas for reform in discussions with stakeholders. The NYISO conducted this review through its 2025 Capacity Market Structure Review project; this report summarizes the findings of the CMSR project. The report first provides an overview of the structure of the ICAP market and the ICAP market's objectives, then summarizes the ICAP market performance over the last decade, and finally details the stakeholder discussions and proposed areas for improvement of the ICAP market structure.

ICAP Market Structure

The ICAP market is intended to incentivize the availability of sufficient resources to meet New York's Resource Adequacy requirements. Resource adequacy in New York State is maintained through a series of related processes administered by the New York State Reliability Council, L.L.C. (NYSRC) and the NYISO. Annually, the NYSRC conducts a probabilistic study to inform its establishment of an installed reserve margin (IRM) for the upcoming Capability Year. The IRM represents an additional quantity of capacity that must be procured above the NYISO's forecasted peak load to meet a resource adequacy criterion of not exceeding a loss of load expectation (LOLE) greater than 0.1 loss of load event days per year. In other words, if the amount of capacity being secured perfectly matched the NYSRC's reliability criterion, it is expected that there will be 1 event in 10 years when resources will be insufficient to meet load, which would result in involuntary load shedding to maintain bulk electric system reliability.

The NYISO's forecasted peak load, plus the additional capacity required to meet the IRM establishes the minimum capacity procurement requirements for the NYCA. The NYISO is also required to establish LCRs for certain transmission-constrained areas (i.e., Localities). There are currently three Localities located in the southeastern/downstate region of New York: (1) the G-J Locality (i.e., Load Zones G, H, I, and J); (2) New York City (i.e., Load Zone J); and (3) Long Island (i.e., Load Zone K).

Figure 1: NYCA ICAP Localities Map



The LCR study utilizes an economic optimization algorithm which takes into account net CONE curves to meet the NYSRC-approved IRM, the LOLE determined for the final case results of the IRM study, and Locality-specific TSL floor values. The Locality-specific TSL floor values serve as lower bounds on the allowable LCRs. In cases where the TSL floor values are greater than the LCRs associated with the NYSRC-approved IRM, the resulting LCRs in combination with the NYSRC-approved IRM can potentially result in a system with an LOLE that is lower than the LOLE associated NYSRC-approved IRM. As a floor value, the TSL floors prevent the LCRs from falling below the transmission security threshold. Such an occurrence is referred to as the TSL floors binding the LCR for a given Locality.

The IRM and the associated study serve as foundational inputs to the NYISO's administration of its ICAP market. These inputs serve as the starting point for deriving various ICAP market parameters, including LCRs, Load Serving Entity (LSE) capacity procurement requirements, Capacity Accreditation Factor (CAF) values, Unforced Capacity (UCAP) availability ratings for capacity supply resources, the availability of capacity import rights, Peak Load Windows for duration-limited resources, and the translation of the ICAP Demand Curves to UCAP terms.

The NYISO's ICAP market is designed to provide sufficient generating capacity to supply energy needs while providing adequate operating reserves. The NYISO ICAP market uses two different measurements to evaluate how much capacity is needed. The first metric is Installed Capacity (ICAP), which looks at generation at full capability (either the maximum tested amount or the nameplate for Intermittent Power Resources such as wind and solar).

The second metric is UCAP, which is the product bought and sold in the ICAP market. UCAP represents the amount of ICAP that is available at a particular time. UCAP essentially represents the amount of ICAP available, adjusted for periods that resources are not available due to forced outages or other limitations on the operating capability of a resource. To reflect the contribution of individual resources towards meeting the NYCA's resource adequacy needs and appropriately reflect the resource's contribution to system reliability in its capacity payment, the NYISO utilizes a capacity accreditation framework. Within this framework, resources are assigned to Capacity Accreditation Resource Classes (CARCs) based on the supplier's chosen participation model and characteristics including energy duration limitation, technology, fuel type, and startup notification time. All resources are then assigned CAFs associated with the corresponding CARC. CAFs, which are determined annually, reflect the marginal reliability contribution of the representative unit of each CARC toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year. The CAF of a resource is then utilized in calculating the amount of UCAP that supplier may provide.

The NYISO uses the NYSRC IRM to calculate the NYCA Minimum Unforced Capacity Requirement and Locational Minimum Unforced Capacity Requirements, which are a percentage of the forecasted peak load for the upcoming year for the NYCA and the Localities, respectively.[1] These requirements are allocated to each LSE based upon the aggregate Adjusted Actual Load data and peak load forecasts provided by Transmission Owners in order to secure sufficient capacity. Unlike other Independent System Operators that operate forward capacity markets (FCMs), the NYISO operates a prompt market. To effectuate this type of ICAP market, the NYISO administers three types of auctions that allow LSEs to procure capacity. These auctions are the (1) Strip or Capability Period Auctions; (2) Monthly Auctions; and (3) Spot Market Auction. The Capability Period Auction runs at least thirty (30) days prior to the start of each Capability Period (6 months),[2] matches bids and offers of fixed MW quantities for the entire Capability Period, and clears all capacity sold in each capacity zone and external interface at a single price per kW-month for each zone and interface. The Monthly Auctions are held at least 15 days prior to the start of each month and match bids and offers of capacity for the remaining months within the Capability Period. Each remaining

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[1] LSEs within a Locality must procure capacity to meet the Locational Minimum Installed Capacity Requirement(s) for the applicable Locality or Localities in which the LSE is located.

[2] The Summer Capability Period runs from May 1 through October 31 of each year, and the Winter Capability Period runs from November 1 of each year through April 30 of the following year.

month of the Capability Period may clear the Monthly Auction at a separate MW quantity and price. The last auction, the Spot Market Auction, is a mandatory auction for LSEs, which takes place every month for the upcoming month. During the Spot Market Auction, the NYISO will procure on behalf of each LSE any remaining capacity needed to meet the LSE's capacity obligations and any excess capacity that it determines is economic to purchase based on the applicable downward sloping ICAP Demand Curve.

The downward sloping ICAP Demand Curves were established to reduce unpredictable market outcomes and potential impacts of market power in the Spot Market Auctions. These curves are set such that an economic new peaking plant could recover its investment cost from the combination of expected revenues from the Energy, Ancillary Services, and ICAP markets if the NYISO needed such a resource to meet its minimum installed capacity requirements. The revenue that such a peaking plant would need from the ICAP market is referred to as net CONE and accounts for the total cost of new entry, called the gross CONE, minus the expected net revenues from the Energy and Ancillary Services market at system conditions that correspond to the minimum installed capacity requirements plus the level of excess corresponding to the capacity of the peaking plant.

The DCR process is a tariff prescribed effort every four (4) years to reassess the parameters of the peaking plant that underlies the ICAP Demand Curves, which is performed by an independent consultant. This effort develops a bottom-up cost estimate for several viable peaking plants. These cost estimates include the construction of the peaking plant, construction of interconnection facilities to the New York grid, supporting infrastructure needed to operate and maintain the plant, costs for routine maintenance and overhaul of the plant, as well as the financing needed to construct the plant. Additionally, models are run to understand the expected net revenues from the Energy and Ancillary Services markets, accounting for physical parameters of the peaking plants, fuel costs, and variable operations and maintenance needs based on operation of the plant. These efforts require significant effort from stakeholders as well as the NYISO and typically take eighteen (18) months to perform.

ICAP Market Objectives

To conduct the comprehensive review of the ICAP market, the objectives of the market were first identified. The objectives determined are as follows:

1. Accurately value resources according to their contribution to maintaining bulk system reliability.
2. Deliver transparent and predictable market outcomes.
3. Operate cohesively with the Energy and Ancillary Services markets to meet the reliability requirements of the evolving grid.

4. Provide appropriate, non-discriminatory, price signals to existing and new resources.
5. Function without unnecessary administrative complexity.
6. Provide an economically efficient, durable, and stable market structure to facilitate investment.

ICAP Market Challenges

There are a series of potential challenges to adapt the ICAP market to the rapidly evolving energy landscape. The traditional ICAP framework was not designed to accommodate entry of resources receiving out of market subsidies as are currently needed for intermittent and energy-limited resources (such as wind, solar and storage) targeted to meet New York State policy goals. As a result, stakeholders have expressed concern with the ICAP market's ability to accurately value the reliability contributions of these new technologies alongside existing resources. CAFs, which were implemented in 2024, provide a critical methodology for addressing resource reliability contributions. The CMSR project is an additional opportunity to consider broader market design improvements.

The ICAP market is also grappling with seasonal reliability risks. As New York continues to address challenging winter system conditions and transitions toward becoming a winter-peaking system due to increased electrification of heating and transportation, the NYISO has begun to study potential loss of load events during the winter.[3] With new seasonal risks, the NYISO has solicited a review of incentives for resources that are critical during winter months, as the current ICAP market structure is heavily oriented toward summer peak demand. This has prompted the NYISO to consider seasonal ICAP Demand Curves and seasonal minimum installed capacity requirements that better reflect evolving load patterns and risk profiles.

Transmission security concerns have become increasingly critical in meeting reliability needs. While this constraint was introduced into the ICAP market in 2019, in the past several years, TSL floors have begun binding the LCR for given Localities. The possibility of a TSL floor binding a Locality has created price signal distortions as resource qualifications and compensation is solely based on meeting resource adequacy needs and does not factor in contributions to meeting transmission security. Stakeholders and the Market Monitoring Unit (MMU) have identified this as an area of concern for the ICAP market.

Stakeholders have additionally raised concerns about the efficiency and effectiveness of uniform pricing mechanisms. They are concerned that such pricing mechanisms may overcompensate existing

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[3] New York Independent System Operator. (2025, February). *Fuel Security: A Growing Winter Reliability Concern*. Retrieved from https://www.nyiso.com/-/fuel-security-a-growing-winter-reliability-concern

resources while failing to provide meaningful investment signals for new capacity, especially when new resource builds are increasingly backed by state contracts, rather than solely by wholesale ICAP market pricing incentives. These concerns have led to discussions around alternative pricing models.

Finally, it is fair to consider if the ICAP market requires undue administrative complexity and if there is an opportunity to improve transparency. The intense iterative process of resetting the ICAP Demand Curves, the introduction of binding transmission security requirements, and volatility and unpredictability of capacity accreditation factors can be difficult for market participants to navigate, potentially deterring new entrants and reducing overall market efficiency. The concerns over the unpredictability of CAFs have become even more acute recently with the selection of a 2-hour battery energy storage system (BESS) as the proxy unit; thus, creating future uncertainty over ICAP market outcomes. Identifying opportunities to simplify the ICAP market design while maintaining reliability, fairness, and proper price signals are key objectives of the CMSR project.

ICAP Market Performance

The ICAP market aims to work in conjunction with the Energy and Ancillary Services markets to send appropriate price signals for resource entry, exit, and retention. To assess the ICAP market's effectiveness in this regard, the NYISO evaluated historical ICAP market results and corresponding resource entry, exit, and investment decisions since 2013. While not the sole indicator of effectiveness, it does provide a measure of alignment with the ICAP market's objectives to attract and retain resources. A key finding of the analysis was the potential impact of the establishment of the G-J Locality on return to service and new resource entry. The creation of the G-J Locality in 2014 resulted in higher market clearing prices for resources located in Load Zones G, H and I. This opportunity for additional ICAP market revenue combined with the anticipated retirement of Indian Point appeared to incentivize approximately 2,300 MW of new resource entry, 500 MW returning to service, and 120 MW of uprates to existing resources since 2014. Figure 2 shows the timing of these new supply additions in relation to relevant ICAP market prices and the Indian Point retirements.

Figure 2: Market Prices vs New Supply in Load Zones GHI

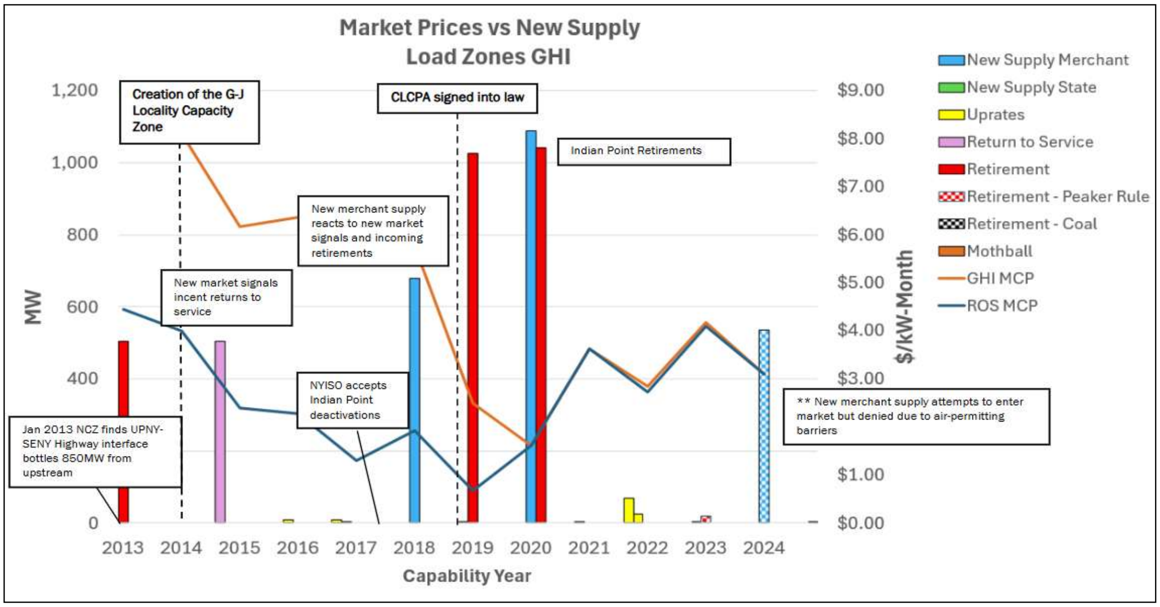
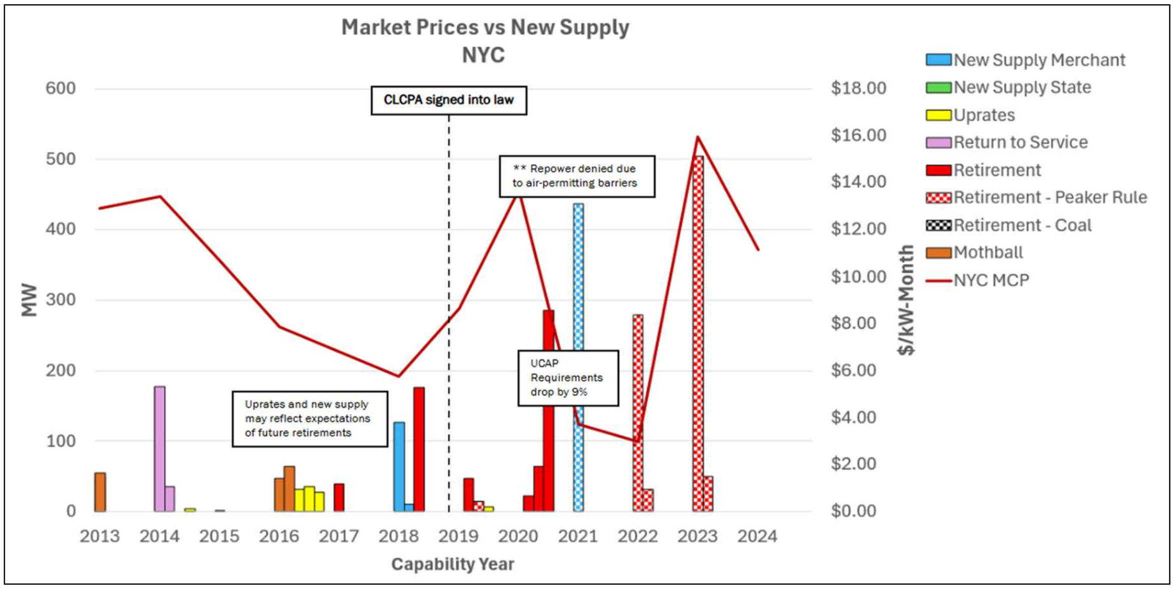


Figure 3: Market Prices vs New Supply in NYC



In the NYC Locality, the anticipation of retirements and higher market clearing prices in 2019 and 2020 may have spurred approximately 575 MW of new resource entry, 260 MW of resources returning to service, and 100 MW of uprates to existing resources in 2016-2018 (Figure 3). Externalities beyond market prices may have also prevented new supply entry in the NYC Locality. For example, in 2021, a merchant developer attempted to repower an existing resource but was denied the necessary air-permit.

Due to excess supply and low market clearing prices, the Long Island Locality and Rest of State capacity zone have exhibited limited entry of merchant supply (Figure 4 and Figure 5). Instead, nearly all new supply was supported by state or utility contracts. This outcome is consistent with the expectations of relatively high excess capacity compared to the minimum installed capacity requirements and low-capacity market prices compared to net CONE.

Figure 4: Market Prices vs New Supply in Long Island

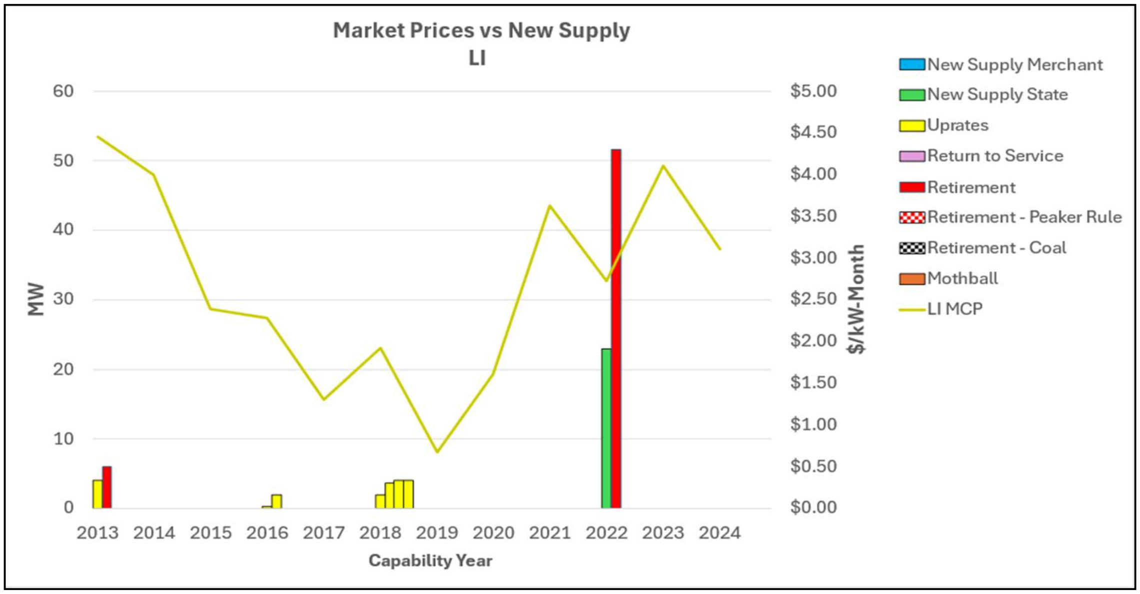
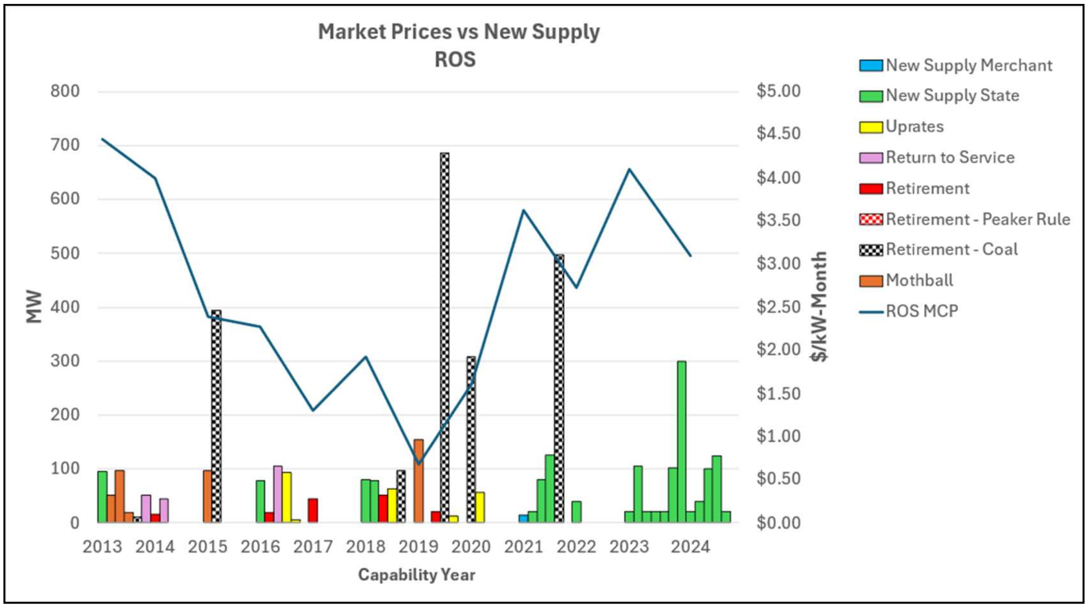
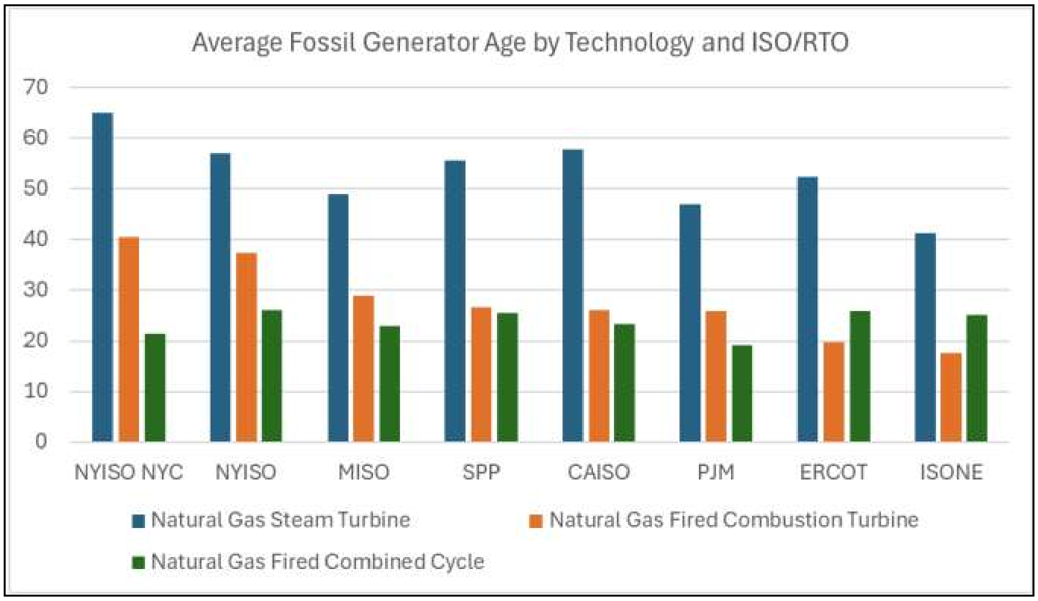


Figure 5: Market Prices vs New Supply in Rest of State



Additionally, as shown in the NYISO's 2025-2034 Comprehensive Reliability Plan,[4] the NYISO's average fossil fuel-fired generation fleet ranks as some of the oldest in the country, as shown in Figure 6below. While there may be additional factors that contribute to these resources choosing to continue participating in the NYISO markets, the age of these resources can also be indicative of a response to effective price signals designed to retain resources, thus meeting reliability at the lowest costs to consumers. The ICAP market provides effective signals that it is valuable to deploy capital to keep existing generators operational, particularly in New York City.

Figure 6: Average Fossil Generator Age



ICAP market performance indicates that new merchant generation, updates, and generator returns to service in the NYCA have been responding to ICAP market signals and anticipated retirements over the past twelve (12) years. However, external factors have impacted the ability for new ICAP suppliers to most efficiently respond to price signals and market dynamics due to permitting constraints and resource constraints in neighboring control areas. This evidence from the past decade is encouraging; it indicates that the fundamental structure of the ICAP market is sound but may be enhanced to support the dynamic needs of the grid in the next decade. Ultimately, the value of a transparent ICAP market signal for resource adequacy provides incentives directly through participation in the wholesale market and supports more efficient contracting beyond the wholesale market itself. Contracting outside the ICAP market can take

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[4] New York Independent System Operator. (2025, October). *2025-2034 Comprehensive Reliability Plan*. Retrieved from: https://www.nyiso.com/documents/20142/54426374/11b_Draft_2025-2034-Comprehensive-Reliability-Plan_OC.pdf/603bab0b-0ec6-ea9e-9786-cd089105843e

many forms (bilateral, Contract for Differences (CFDs), offtake agreements, or even Renewable Energy Credits by New York State). These outside contracts enable investors to hedge against market risk and provide the basis for financing arrangements for large deployments of capital. The NYISO markets represent the short-term value of the product to meet the current reliability needs but form the basis of long-term financial arrangements outside the market.

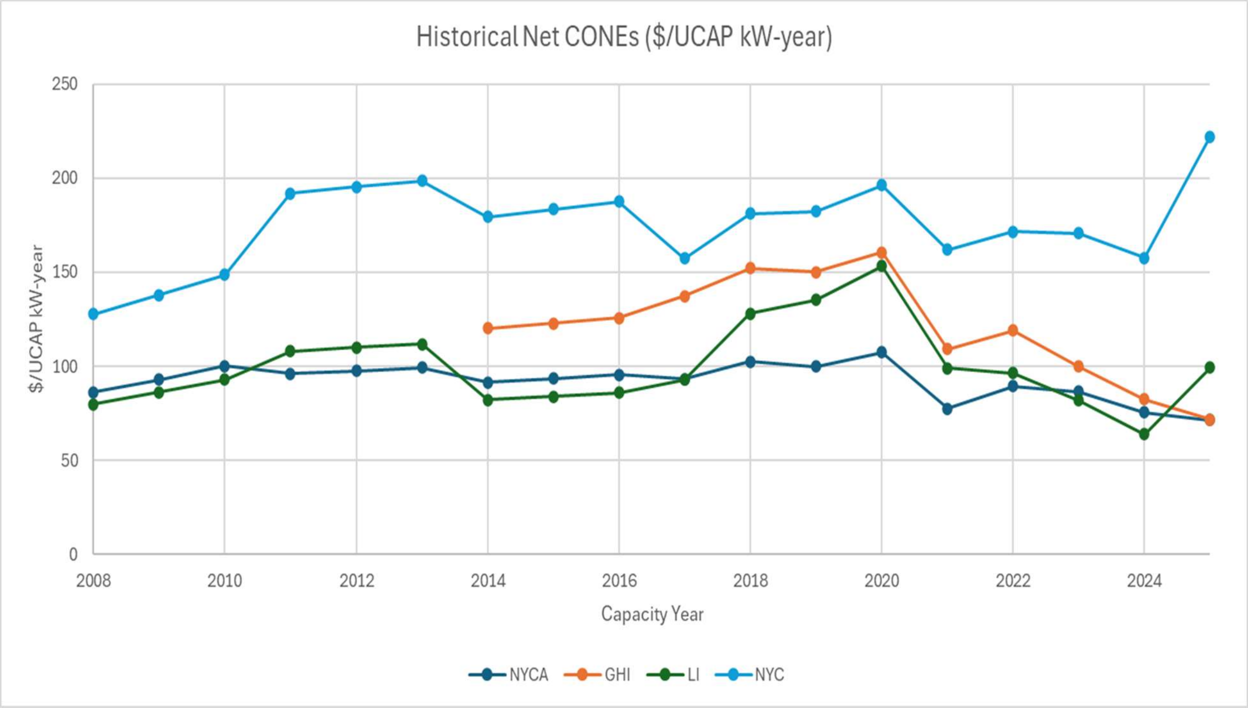
Capacity Market Structure Review Stakeholder Process

During the 2024 stakeholder annual Sector meetings, participants expressed an interest in completing a comprehensive review of the ICAP market to understand if the foundational structure remains effective and to consider what changes may be needed. This was followed by a robust discussion of the topic at the 2024 Joint Board and Management Committee meeting in June 2025. Following this feedback and consideration as part of the project prioritization process for 2025, the NYISO began planning for this effort. This 2025 engagement included a kick-off with stakeholders, the establishment of project and ICAP market objectives, and a review of options for exploration. To assist in this effort, the NYISO engaged FTI Consulting. The NYISO, in consultation with stakeholders and the MMU, undertook a comprehensive review of potential areas of exploration, actively engaging stakeholders through a series of workshops and working group meetings (Appendix B – Additional Reports and Presentations). This collaborative process invited market participants, consumer advocates, developers, and regulatory bodies to explore a range of design alternatives. This resulted in numerous presentations by the NYISO as well as reports prepared by FTI Consulting and the MMU. This inclusive approach allowed the final prioritized recommendations to reflect a balanced consideration of reliability needs, investment signals, and consumer cost impacts. NYISO began by facilitating open dialogue by presenting the ideas described below. This report is intended to reflect the culmination of this stakeholder process.

A. ICAP Demand Curve Reset Process and Methodology Enhancements [Prioritized]

The Demand Curve Reset process is conducted every four years to recalibrate the ICAP Demand Curves. The current process for establishing the gross CONE and net Energy and Ancillary Services (EAS) revenues may not be conducive to meeting the CMSR project’s goals to deliver transparent and predictable market outcomes and provide an economically efficient, durable, and stable market structure to facilitate investment. The NYISO expressed concern that unpredictable net CONE levels may increase in the future as the drivers of capacity supply resource investment continue to change at a rapid and unpredictable rate (see Figure 7). The current DCR process also involves extensive collaboration and analysis, which some stakeholders consider overly complex and time intensive.

Figure 7: Historical Net CONEs



Additionally, the NYISO explored revisiting the structure of the ICAP Demand Curves, which have remained largely unchanged since 2003. An alternative shape may better reflect the reliability value of incremental capacity. Marginal Reliability Improvement (MRI) curves are constructed by adding modeled supply to a system and the marginal reliability benefit provided by the next increment of supply decreases, producing a downward sloping MRI curve. This concept may be worth pursuing to develop effective and appropriate ICAP Demand Curves.

B. Winter Reliability Capacity Enhancements [Prioritized]

The ICAP market has historically been designed around summer peak demand; however, increasing winter reliability risks driven by electrification and fuel security concerns have brought increased attention to the seasonal structure of the ICAP market. The NYISO began working on Winter Reliability Capacity Enhancements in 2024 with the publication of the Winter Reliability Issue Discovery Report.[5] Building off that report, the NYISO kicked off the Winter Reliability Capacity Enhancements project, a separate ICAP market design concept proposal that has run in parallel with the CMSR project effort. NYISO staff and stakeholders collaborated to consider establishing seasonal minimum ICAP requirements and

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[5] New York Independent System Operator. (2024). Winter Reliability Capacity Enhancements: Issue Discovery Report. Retrieved from https://www.nyiso.com/documents/20142/48542026/Winter%20Reliability%20Capacity%20Enhancements%20ID%20Report_Final.pdf

elections, refining capacity accreditation factors, and enhancing seasonal ICAP Demand Curves to better reflect winter system needs. Through these proposed enhancements, the NYISO aims to continue to send appropriate signals for winter preparedness through the ICAP market, particularly considering fuel supply constraints and generator performance challenges during extreme cold weather events. By recalibrating market inputs and rules to reflect seasonal shifts in peak demand, the NYISO seeks to maintain reliability while supporting efficient investment and resource retention.

In alignment with the broader CMSR project objectives, the Winter Reliability Capacity Enhancements project has emphasized transparency, predictability, and economic efficiency. The proposed seasonal elections for UDRs and EDRs seek to improve the accuracy of capacity availability assumptions, while proposed development of seasonal ICAP Demand Curve formulas, such as removing the seasonal capacity availability adjustments, aims to better reflect actual NYCA system needs. As part of that effort, the NYISO has recommended retaining annual CAFs to avoid seasonal volatility and adverse incentives, while still capturing winter reliability value as seasonal risk profiles shift. These proposed targeted enhancements seek to reduce administrative complexity and allow the ICAP market to continue to be a robust tool for maintaining reliability across all seasons, particularly as New York transitions to a winter-peaking system.

C. Reliability Attribute-based Capacity Pricing [Prioritized]

An attribute-based capacity market seeks to better align market incentives with the evolving reliability needs of New York's power grid. This approach would aim to reenvision the ICAP market from being primarily driven by resource adequacy concerns to a market that can value additional resource attributes. Additional attributes that could be evaluated are resource dispatchability, duration limitations, and cycling ability. These attributes could be considered for capacity accreditation and as a compensation framework. This design market concept aims to more accurately reflect each resource's contribution to system reliability, especially as the grid transitions toward a mix dominated by intermittent renewables and energy-limited technologies. The attribute-based design may provide distinct ICAP market signals based on measurable reliability value that may allow the market to support investment in resources that can perform during critical system conditions.

Given their inherit symmetry, the NYISO intends to combine this effort with the Valuing Transmission Security effort discussed below.

D. Capacity Zone Redesign [Prioritized]

The Capacity Zone Redesign project began in 2024 with the Granular Capacity Zonal Pricing Issue

Discovery Report.[6] This design effort seeks to improve the locational accuracy and efficiency of capacity pricing. While effective in identifying broad reliability needs, the current zonal framework may not fully capture emerging transmission constraints, shifting load patterns, and the reliability contributions of distributed and flexible resources. Enhancing capacity zones could involve redefining zone boundaries, introducing sub-zonal granularity, or incorporating dynamic transmission security constraints into the market clearing process. Additionally, areas of exploration may include evaluating the limitations of the current deliverability test in defining capacity zone boundaries and the current omission of bi-directional interface constraints. These changes aim to better reflect the true value of capacity in constrained areas, support more targeted investment signals, and align with evolving grid conditions.

Enhancing the capacity zonal structure and zone-setting processes may improve locational price signals and provide more efficient compensation for both new and existing resources. However, implementation would require careful coordination with transmission planning, stakeholder engagement, and regulatory approval for transparency and to avoid unintended market distortions.

E. Valuing Transmission Security [Prioritized]

The current ICAP market structure primarily compensates for resource adequacy and only indirectly compensates resources for transmission security. The ICAP market considers transmission security by establishing TSL floor values as a lower limit on the allowable LCR values. In 2024, as part of the Valuing Transmission Security project, the NYISO highlighted the potential issues with the current representation of transmission security needs in the ICAP market and how the NYISO can incorporate transmission security valuation into its capacity market designs to better reflect the locational reliability contributions of resources.[7] By integrating transmission security into capacity pricing either through refined capacity accreditation, zonal enhancements, or locational marginal reliability metrics, resources located in transmission-constrained areas may be more appropriately compensated for their reliability value. This approach may improve investment signals in areas where transmission limitations pose risks to system adequacy, reduce reliance on out-of-market reliability contracts, and support more efficient grid planning.

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[6] New York Independent System Operator. (2025). Granular Capacity Zones Issue Discovery Final Report. Retrieved from https://www.nyiso.com/documents/20142/48542026/Granular%20Capacity%20Zones%20Issue%20Discovery%20Final%20Report.pdf/988bd383-2328-d36f-dbad-f833bec20725

[7] New York Independent System Operator (NYISO). (2023). Valuing Transmission Security: Final Issue Discovery Report. Retrieved from https://www.nyiso.com/documents/20142/48542026/VTS%20Final%20Issue%20Discovery%20Report%20clean%20for%20posting.pdf/88571834-7431-9b88-66a4-574a36a28a5e.

However, implementation would require enhanced modeling capabilities, stakeholder consensus on valuation methods, and coordination with transmission planning processes for transparency and fairness. Future market design enhancements that better align market signals with both resource adequacy and transmission security needs may strengthen grid reliability while efficiently compensating resources for their contributions to system stability.

Given the inherit symmetry, this effort will be combined with the Reliability Attribute-Based Capacity Pricing project described above.

F. Improving Capacity Accreditation and Resource Adequacy Modeling [Prioritized]

The Improving Capacity Accreditation and Resource Adequacy project would explore adjustments to marginal capacity accreditation and resource adequacy modeling processes that may improve ICAP market stability, enhance transparency and predictability, and support more informed decision-making by market participants. Adjustments could include, but are not limited to, adopting an alternative marginal capacity accreditation calculation, or utilizing additional historical input data into the resource adequacy model. The NYISO is concerned that the complexity and limited visibility into the resource adequacy models may reduce transparency and predictably of market outcomes and limit the ability of the ICAP market to provide an economically efficient, durable and stable market structure to facilitate investment.

G. Locational Marginal Capacity Pricing (C-LMP) [Non-Prioritized]

The Capacity Locational Marginal Price (C-LMP) framework aims to set capacity prices based on the MRI of resources at specific locations, aligning prices with the marginal contribution of each resource to system reliability at their nodal interconnection point. The approach aims to enhance market efficiency by eliminating the need for individual Locality-specific demand curves and instead determining prices based on the MRI and a system-wide reliability parameter.[8] C-LMP is intended to enhance market efficiency by producing more granular and economically reflective price signals.

The NYISO identified several concerns with such a market design. Specifically, C-LMP faces potential challenges in administration, feasibility, managing price volatility/unpredictability, and accurately calculating marginal reliability impacts at specific locations, which could lead to unpredictable outcomes. Due to these concerns, the NYISO removed C-LMP from its list of prioritized market design pathways. However, elements of C-LMP can be explored as potential ICAP market enhancements, including incorporating transmission security into the ICAP market and improving the capacity zone design.

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[8] See 2022 State of the Market Report for an overview of C-LMP.

H. Value of Lost Load [Non-Prioritized]

The Value of Lost Load (VoLL) represents the economic cost of an electrical outage, reflecting the value customers place on uninterrupted power supply. The NYISO explored the concept of VoLL as a foundational metric for price-setting mechanisms in the ICAP market, such as the demand curve, which currently relies on the Cost of New Entry. A VoLL framework could seek to directly link ICAP market outcomes to the economic value of reliability. This design aims to produce more economically efficient investment signals and maintain reliability at a level that reflects consumer preferences where VoLL is calculated to the cost to consumers of an unserved megawatt-hour of electricity.

However, estimating outage costs to determine VoLL is an extremely complex process[9] that can be prone to inaccuracies and overestimations. Translating VoLL into a seasonal capacity price introduces additional uncertainty and complexity, further complicating market efficiency and potentially distorting pricing signals. Setting ICAP market requirements based on VoLL may not meet Northeast Power Coordinating Council and NYSRC reliability standards. The NYISO's evaluation of VoLL revealed it is unlikely that a VoLL market design would be more accurate nor easier to administer than the exiting net CONE calculation.

I. Bifurcated Capacity Markets: New vs Existing Resources [Non-Prioritized]

Some NYISO stakeholders requested that the NYISO explore a bifurcated capacity market design that distinguishes between new and existing resources in the pricing and procurement of capacity. This concept was identified by stakeholders as potentially addressing their concern that the current uniform pricing model may overcompensate existing resources while failing to reflect the actual drivers of new investment, which may be increasingly driven by state contracts rather than market signals. Certain stakeholders expressed concern that (1) new resources, which typically involve higher initial capital costs and longer payback periods, may require higher capacity payments to support investment and (2) existing resources, with lower capital costs but higher operating costs due to aging infrastructure, would participate under standard market conditions and may receive lower compensation.

A potential bifurcated design would establish separate demand curves or price caps for new and existing resources, potentially reducing consumer costs in the short term by lowering payments to legacy

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[9] Will Gorman, The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages, 35 The Electricity Journal

107187, 2022 https://doi.org/10.1016/j.tej.2022.107187. (providing an overview of methods used to estimate VoLL).

assets. However, the MMU[10] and consultants[11] have cautioned that such a market structure could lead to long-term inefficiencies, including premature retirements of cost-effective existing resources and distorted investment incentives. The NYISO agrees with those concerns. Additional analysis of bifurcated markets is included in a separate section of this report.

J. Forward Capacity Market [Non-Prioritized]

In a FCM, capacity is procured several years in advance of the delivery period through an auction to provide long-term investment signals and ensure resource adequacy. This contrasts with NYISO's current short-term prompt ICAP market structure with no long-term forward commitments beyond the seasonal Capability Period Auctions. Resources that clear a FCM auction commit to being available during the designated delivery period, typically three years in advance, with penalties and incentives designed to secure sufficient supply to meet forecasted reliability needs. The FCM structure is designed to provide revenue certainty for new resources and allows system operators to plan for future capacity needs based on long-term demand forecasts. FCMs are currently implemented in ISO-NE and PJM.[12]

Stakeholders did not indicate support for prioritizing any FCM design efforts for further consideration in the CMSR project. The NYISO previously evaluated the potential benefits and drawbacks of moving to an FCM design and concluded that a move to an FCM design was not warranted.[13] FCMs require more complex auction designs, qualification processes, and monitoring mechanisms than the current ICAP market design implementation. There is also increased potential for FCMs to be inefficient and unstable due to inaccurate long-term load forecasting. An inaccurate long-term forecast can create a mismatch in procurement; over-procurement would increase consumer costs and shift risks onto consumers, while under-procurement would leave the system vulnerable to reliability issues.

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[10] Potomac Economics. (2025, May 22). *MMU CMSR Discussion*. Retrieved from https://www.nyiso.com/documents/20142/51574954/MMU%20CMSR%20%20Discussion%2005-22-25.pdf/07ad280f-78be-f858-d27c-ed6033a64a1f

[11] FTI Consulting. (2025, May 22). *Workshop on Discriminatory Capacity Auction Design*. Retrieved from https://www.nyiso.com/documents/20142/51574954/2%20Workshop%20on%20Discriminatory%20Capacity%20Auction%20Design%20-%20052225%20icap.pdf/9d71f2ba-cd0c-08be-3851-5da9a26769a1

[12] Federal Energy Regulatory Commission. *Understanding Wholesale Capacity Markets*. Retrieved from https://www.ferc.gov/understanding-wholesale-capacity-markets

[13] Paul Hibbard, Todd Schatzki, Craig Aubuchon, and Charles Wu, "NYISO Capacity Market, Evaluation of Options," May 2015. https://www.analysisgroup.com/globalassets/content/insights/publishing/nyiso_capacity_market_evaluation_of_options.pdf

Prioritization Efforts

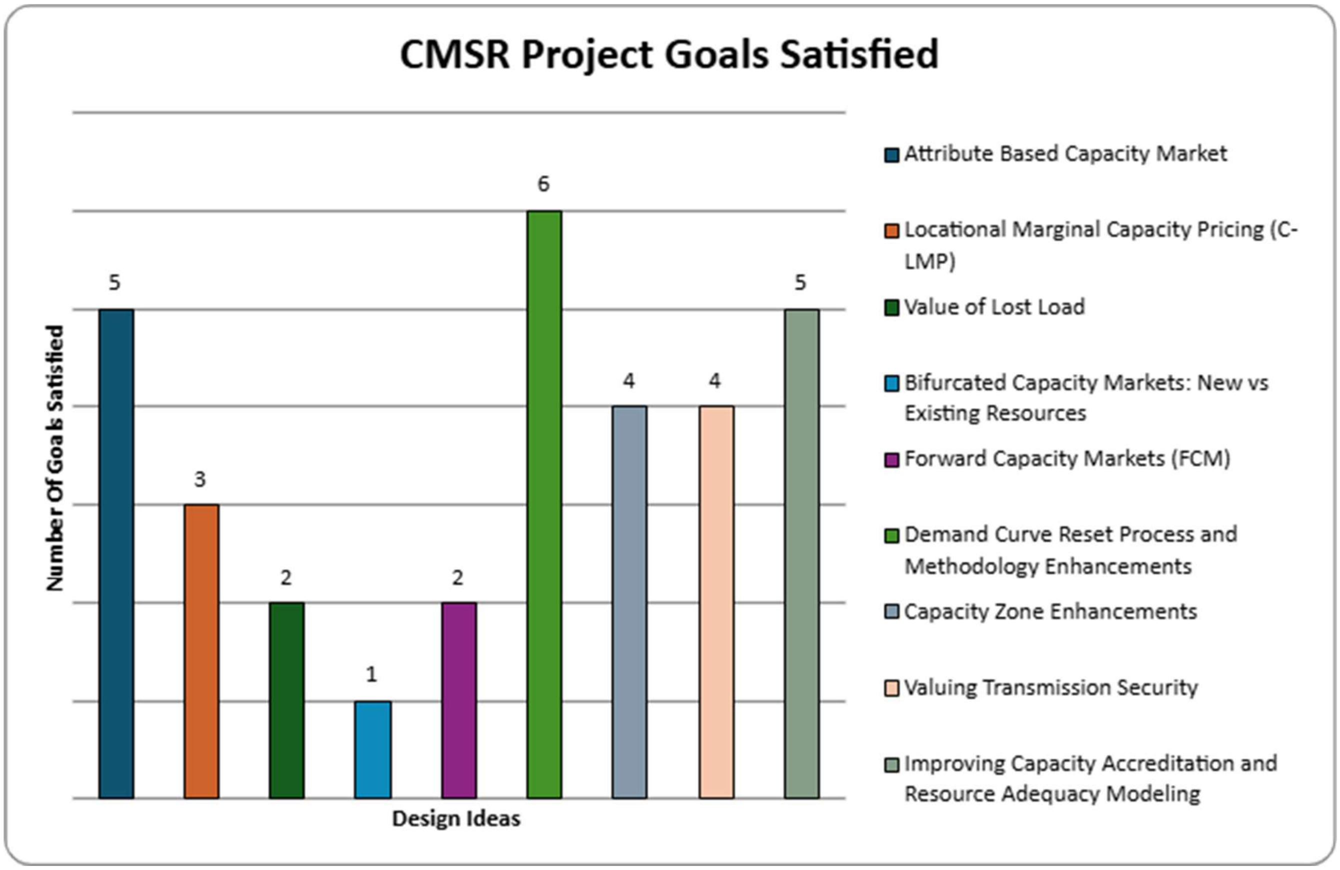
The CMSR project's stakeholder process eventually focused its efforts on prioritizing designs for future project exploration by the NYISO. The results of the stakeholder rankings for the efforts in 2026 can be found in the Appendix. While many ideas were discussed, the areas that drew the most support and consideration aligned with the CMSR project's defined objective of identifying ICAP market structures that will help facilitate New York's evolving grid consistent with policy goals and achieve the following objectives:

1. Accurately value resources according to their contribution to maintaining bulk system reliability;
2. Deliver transparent and predictable market outcomes;
3. Operate cohesively with the Energy and Ancillary Services markets to meet the reliability requirements of the evolving grid;
4. Provide appropriate, non-discriminatory, price signals to existing and new resources;
5. Function without unnecessary administrative complexity; and
6. Provide an economically efficient, durable, and stable market structure to facilitate investment.

Figure 8: CMSR Project Goals Satisfied by Each Design Idea

NYISO CMSR Design Ideas and Capacity Market Goals	Accurately value resources according to their contribution to maintaining bulk system reliability.	Deliver transparent and predictable market outcomes	Operate cohesively with the Energy and Ancillary Services markets to meet the reliability requirements of the evolving grid.	Provide appropriate, non-discriminatory, price signals to existing and new resources.	Function without unnecessary administrative complexity.	Provide an economically efficient, durable, and stable market structure to facilitate investment.
Attribute Based Capacity Market	X	X	X	X		X
Locational Marginal Capacity Pricing (C-LMP)	X		X	X		
Value of Lost Load	X			X		
Bifurcated Capacity Markets: New vs Existing Resources	X					
Forward Capacity Markets (FCM)		X		X		
Demand Curve Reset Process and Methodology Enhancements	X	X	X	X	X	X
Capacity Zone Enhancements	X	X		X		X
Valuing Transmission Security	X		X	X		X
Improving Capacity Accreditation and Resource Adequacy Modeling	X	X		X	X	X

Figure 9: CMSR Project Goals Satisfied



To meet these objectives, the NYISO recommends prioritizing the following projects:

1. ICAP DCR Process and Methodology Improvements
2. Winter Reliability Capacity Enhancements
3. Reliability Attribute-Based Capacity Pricing
4. Capacity Zone Redesign
5. Improving Capacity Accreditation and Resource Adequacy Modeling

The ICAP DCR Process and Methodology Improvements project must consider any proposed changes to the DCR process within the quadrennial cycle and before the next reset begins for the scheduled 2029 Demand Curve Reset. The Winter Reliability Capacity Enhancements project is also a time-sensitive priority to address the growing reliability concerns in winter. The Reliability Attribute-Based Capacity Pricing and Capacity Zone Redesign projects are also prioritized and are intended to commence after the first two projects. Any changes to the ICAP Demand Curves as part of the ICAP DCR Process and Methodology Improvements project and the annual structure of the ICAP market through the Winter

Reliability Capacity Enhancements project must be timely pursued. If implemented, these ICAP market enhancements may change the issue statements of Reliability Attribute-Based Capacity Pricing and Capacity Zone Redesign projects.

ICAP DCR Process and Methodology Improvements

The NYISO provided a comprehensive overview of the ICAP Demand Curve Reset Process and Methodology Enhancements project design track to the Installed Capacity Working Group.[14]

Several alternatives were explored, including leveraging existing publications of resource costs (e.g., National Renewable Energy Laboratory (NREL) and Energy Information Administration (EIA) data) instead of continuing the current bottom-up engineering assessments conducted by consultants every DCR, modifying the shapes and slopes of the ICAP Demand Curves, and adopting an "empirical net CONE" approach based on historical market clearing prices. These changes aim to improve the stability of reference point prices to help deliver appropriate price signals and provide transparent and predictable market outcomes.

Historically, the DCR process has relied on bottom-up engineering assessments to estimate capital costs for peaking technologies. These assessments may negatively impact market predictability and transparency and have often been resource-intensive without significant added value. NYISO explored using publicly available data from sources such as the EIA Annual Energy Outlook (AEO) and NREL Annual Technology Baseline (ATB) to streamline the process including regional assumptions of overnight capital costs for new power plants. The EIA AEO provides an annual assessment of long-term energy trends in the United States. The overnight capital costs are generally re-evaluated every 3-5 years with support from an external engineering consultant and are adjusted annually between the re-evaluation years based on the producer price index for metals and metal products. Since 2015, NREL has published an ATB annually, which documents normalized technology costs and performance assumptions using published sources. Figure 10 illustrates a comparison of overnight capital costs for simple cycle gas turbines across NYISO, EIA, and NREL estimates. Notably, NYISO's estimates have consistently been higher, likely due to assumptions around dual-fuel capability and emissions controls.

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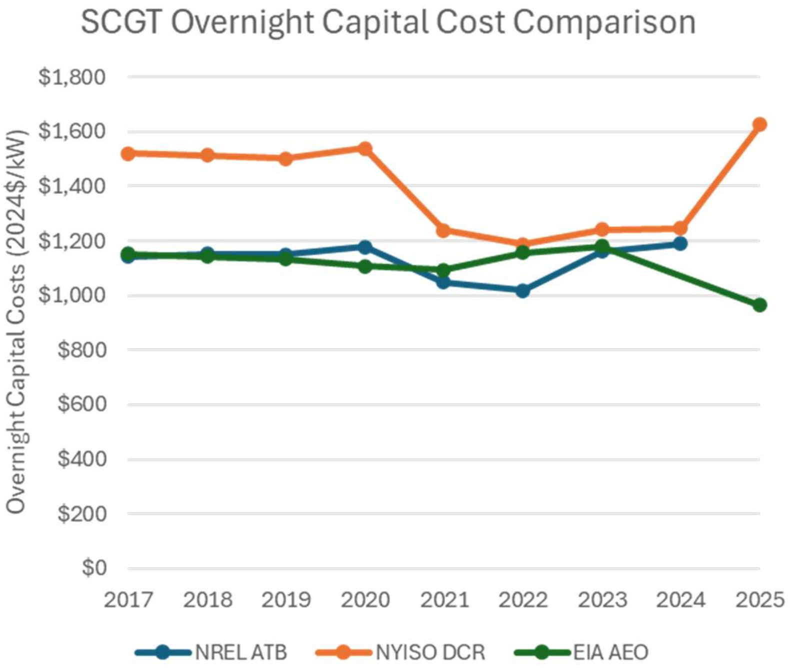
[14] Mohrman, M. (2025, May 22). *Capacity Market Structure Review: ICAP Demand Curve Reset Process and Methodology Improvements* [Presentation]. Installed Capacity Working Group (ICAPWG), New York Independent System Operator. Retrieved from https://www.nyiso.com/documents/20142/51574954/4%20CMSR%20DCR%20-%2005222025%20ICAPWG.pdf/3b0c1a46-847a-91bc-b63b-8fd6169892eb

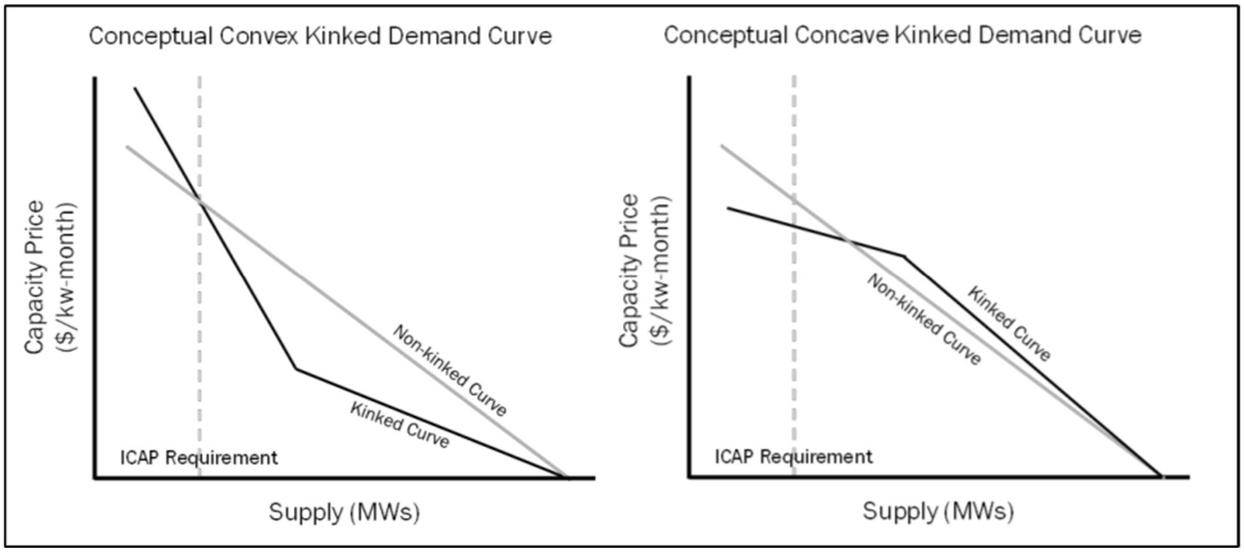
Figure 10: Simple Cycle Gas Turbine Capital Cost Comparison



NYISO also explored the use of empirical net CONE as an alternative to modeled estimates. This approach would base reference point prices on historical market clearing prices at which new resources entered the market. The benefit to this approach would be removing the assumptions related to financing, future net EAS revenues, and capital costs that may differ from the conditions experienced by any single developer. An empirical net CONE would instead use the historical market clearing prices that actual new supply has entered the market in past capacity auctions. However, there are some concerns with this approach. Chiefly, there are unique investment conditions applicable to each resource that may not be transferable to all resource new entry and vary greatly by resource type.

The concept of linear kinked curves was also explored by the NYISO (Figure 11). A concave curve can be used as a simplified linear approximation of the MRI curve. Linearizing the MRI curve can provide additional price stability as compared to the true MRI smooth curve. A kinked convex curve could provide unique benefits with a flatter slope near the reference price. This flatter slope could reduce the impact of the level of excess adjustment and provide additional stability in market outcomes when the market clears closer to requirement conditions. However, as part of the 2008-2011[15] and 2011-2014[16] DCRs, NERA Economic Consulting evaluated a convex kinked demand curves and noted market power and regulatory risk concerns, despite the potential price stability advantages.

Figure 11: Conceptual Kinked Demand Curves



Improvements to both the methodology underlying the demand curves and the process for establishing them may reduce administrative burdens while supporting efficient market signals for resource entry and exit. The NYISO and its stakeholders are optimistic about prioritizing this design tract for further development.

The NYISO has identified four key areas for potential enhancements and further exploration with z

1. Proxy Unit Definition
2. Net CONE Estimates
3. DCR Process Improvements
4. ICAP Demand Curve Shape and Slope

Stabilizing the anchoring of the ICAP Demand Curves will stabilize the predictability of ICAP market

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[15] NERA Economic Consulting & Sargent & Lundy. (2007, August 24). Independent study to establish parameters of the ICAP demand curve for the New York Independent System Operator. New York Independent System Operator. Retrieved from https://www.nyiso.com/documents/20142/1401396/ICAPWG_Demand_Curve_Study_Report_final_82407.pdf

[16] NERA Economic Consulting & Sargent & Lundy. (2010, September 3). Independent study to establish parameters of the ICAP demand curve for the New York Independent System Operator. New York Independent System Operator. Retrieved from https://www.nyiso.com/documents/20142/1410950/Demand_Curve_Study_Report_9-3-10_clean.pdf

outcomes. While NYISO markets have worked as intended since their inception, the resetting of the ICAP Demand Curves every four years degrades the ability to forecast prices that are critical for informing investment decisions. Enhancing the durability of the demand curve anchors can provide the NYISO market participants with greater trust in forecasting their market participation decisions and shifts their predictive efforts to meeting the dynamic needs of the Energy Market.

The ICAP DCR Process and Methodology Improvements project shows promise in delivering benefits to the NYISO and its stakeholder community. A streamlined and improved DCR process has the potential to shift future NYISO market design and stakeholder efforts away from the lengthy reset process to anticipating and developing the market design enhancements of the evolving grid of tomorrow. Reducing administrative complexity can enhance market participation across all NYISO sectors for new and existing participants.

Proxy Unit Definition

The tariff provides that the peaking plant for each ICAP Demand Curve must represent the "technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable." Although designed to provide flexibility, this construct has also produced uncertainty and significant contention over time. Such uncertainty, in part, derives from the relative lack of prescript standards for identifying "economically viable" technology options. Although the Federal Energy Regulatory Commission (FERC) has consistently held that, as a threshold matter, a technology must be technically/operationally viable, FERC has also stated that all additional criteria for assessing economic viability are a matter of judgment.[17] NYISO has used screening criteria for several DCRs which have been acknowledged as appropriate by FERC. These include (1) availability of the technology to most market participants; (2) operating experience sufficient to demonstrate that the technology is proven; (3) dispatchability and capability of being cycled to provide peaking service; and (4) capability of meeting applicable environmental requirements and ability to be practically constructed in the capacity region at issue.

The NYISO proposes exploring refinements to the current tariff definition of the peaking unit to incorporate certain attributes the NYISO has identified as important for meeting reliability needs. This approach is not intended to prescribe any specific technology. Instead, the refinements seek to clarify certain minimum operating characteristics a technology should possess to be eligible for consideration in

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[17] Federal Energy Regulatory Commission (FERC). *Commissioner James Danly and Commissioner Neil Chatterjee Joint Dissent in Part on New York Independent System Operator, Inc.* Docket No. ER21-502-001. April 9, 2021. Available at: https://www.ferc.gov/news-events/news/commissioner-james-danly-and-commissioner-neil-chatterjee-joint-dissent-part-new.

establishing the ICAP Demand Curves. Specifically, in addition to the screening criteria listed above, the NYISO has initially identified the following reliability attributes an eligible technology should satisfy:

- Capable of assisting in resolving transmission security needs and responding to reliability-driven dispatch.
- Capable of providing existing Operating Reserves.
- Attributes consistent with availability in meeting reliability needs as reflected by Capacity Accreditation Factor, i.e., firm fuel.

Net CONE Estimates

The NYISO would like to preliminarily explore if there is an opportunity to restructure the development of net CONE to improve predictability, transparency and economic efficiency of the ICAP Demand Curves. Two components could be evaluated further as part of the design: (1) moving to the development of "long-run" gross CONE estimates or other gross CONE setting methods and (2) adjusting net EAS revenue offset calculation to compliment any corresponding changes to gross CONE. Gross CONE, or the total cost of new entry, less the net EAS revenue offset yields the net CONE value.

DCR Process Improvements

Although the NYISO is contemplating a proposal that would shift toward a more technology-agnostic approach for determining net CONE, periodic reviews of underlying assumptions and methodologies would remain important. Any proposal would likely need to contemplate the retention of a streamlined, periodic review process.

The proposed enhancements would seek to leverage the existing annual update process for formulaically adjusting certain values over time. For example, inflationary indices or other cost trend-tracking publications (e.g., the Handy-Whitman Index) could be leveraged to adjust the long-run gross CONE estimates annually. These publications track the inflationary adjustment to generation equipment closer than a normal core inflation index. The proposed enhancements could also seek to extend the annual update process to include updates to certain financial parameters through tracking year-to-year changes in certain key market indicators. Formulaic adjustments to the shape and slope of the curves could also be developed to incorporate adjustments in response to anticipated market entry and exit. Collectively, these changes are intended to reduce significant step changes over time by reflecting incremental changes annually.

The NYISO contemplates a streamlined periodic review process to provide an opportunity for reviewing underlying assumptions and the basis for annual adjustments so that the curves remain aligned with market conditions and expectations over time. The streamlined review can also provide updated near-term gross CONE estimates for inclusion in the dataset for deriving the proposed long-term estimates. Updates to net EAS revenue offsets and/or the methodology for deriving such estimates could also be evaluated as part of such streamlined periodic review (e.g., accounting for revenues from new market products and market design enhancements). Based on the revised scope and function of a streamlined periodic review, the NYISO contemplates that such reviews could be conducted less frequently than every four years and should be less burdensome.

ICAP Demand Curve Shape and Slope

The NYISO proposes exploring modifying the current ICAP Demand Curve shapes and slopes to better reflect differing market and system conditions across capacity regions. The existing linear demand curves apply a “one size fits all” approach, which may not be appropriate given the diversity in reliability needs and market dynamics in various regions of New York. In addition, enhancements to the existing curves can provide for better alignment with the potential reliability value of additional capacity beyond minimum requirements.

The NYISO proposes to further explore the following aspects of the demand curves:

1. Shape – the current linear shape is not indicative of the marginal reliability value of additional capacity and thus can cause consumers to be over or under paying for capacity.
2. Zero Crossing Point (ZCP) – The current ZCPs in the Localities were established decades ago and are not indicative of reliability needs, nor the value of incremental capacity.
3. Level of Excess – This value is currently set by the size of the proxy unit (200 MW). However, this little margin can create a scenario where market exit would lead to the inability to meet reliability requirements (particularly in Localities).

Early modeling of potential alternative demand curve shapes has shown significant potential savings for consumers.

Winter Reliability Capacity Enhancements

The Winter Reliability Capacity Enhancements project is a priority needed to address the new and developing seasonal reliability risks in winter. NYISO has been a summer peaking system; therefore, the ICAP market was built as a summer-centric capacity market. In 2022, Winter Storm Elliot highlighted NYCA system vulnerabilities with the dependence on non-firm gas supplies to support electric generation. Unlike summer peaks, winter reliability risks often stem from fuel supply constraints, Generator outages, and extreme cold weather events. Prioritizing this ICAP market enhancement seeks to address these challenges to position the ICAP market to attract and retain the resources needed to support winter reliability needs.

The NYISO has proposed winter reliability capacity enhancements distinct from its broader CMSR project effort. In December 2024, NYISO presented its Winter Reliability Capacity Enhancements Issue Discovery Report,[18] which addressed some of the challenges with the expected increased winter resource adequacy risk and potential areas for evolving the NYISO ICAP market to respond to these anticipated changes. Several issues identified were near-term issues that reflect current procedures and calculations that could be recalibrated so that the ICAP market continues to send appropriate price signals. Longer-term issues were also identified, which may have required a reassessment and restructuring of the current resource adequacy process and/or development of new processes. The NYISO prioritized four key components of the ICAP market for exploration in 2025:

1. Seasonal Minimum ICAP Requirements
2. Seasonal Elections
3. Capacity Accreditation Factors
4. Seasonal Demand Curve Enhancements

The components that were evaluated as part of the Winter Reliability Capacity Enhancements project have implications for the CMSR project that must be considered.

Seasonal Minimum ICAP Requirements

To address increasing winter reliability risk, a winter requirement can be established without changing the NYSRC's current annual IRM setting process. The NYISO proposes establishing NYCA Winter ICAP Requirements based on the final IRM study case reflecting the NYSRC-approved IRM. The Winter ICAP Requirements and LCRs would be derived from the NYCA Minimum ICAP Requirement and maintain the annual 1-in-10 LOLE requirement set by the NYSRC.

The LCR study process, including inputs to the LCR Optimizer such as the final IRM base case, the NYSRC-approved IRM, and the targeted LOLE, would remain unchanged. The Winter LCRs would be derived from the available capacity in each Locality in the winter peak month of the final IRM base case, like the Winter NYCA ICAP Requirement.

Seasonal TSL floor values would be calculated for the Summer and Winter Capability Periods to

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[18] New York Independent System Operator (NYISO). (2025). Winter Reliability Capacity Enhancements ID Report. Retrieved from https://www.nyiso.com/documents/20142/48542026/Winter%20Reliability%20Capacity%20Enhancements%20ID%20Report_Final.pdf/fbbcbc9f-85e7-c7bd-8ff9-30aa9e84ac1e

account for seasonal differences in assumption parameters. The LCR Optimizer would use the more restrictive seasonal TSL floor value to procure sufficient resources to meet transmission security on an annual basis as well as to account for the retention of annual capacity removal in the IRM and LCR study process.

Seasonal Elections

In preparation for each upcoming Capability Year, market participants submit annual election information to the NYISO by August 1 preceding the Capability Year, indicating their intended market behavior. Annual elections are collected for use in the reliability studies that determine the NYCA IRM and associated LCRs. After evaluating seasonal enhancements for all current annual election types, the NYISO has recommended that only UDRs and EDRs elections should be seasonal. This determination was based on the expectation that certain UDRs and EDRs will not have the same capability to deliver capacity in winter, which may directly impact reliability requirements and may lead to undesirable market outcomes if not accounted for accurately.

UDRs and EDRs are rights that allow for an incremental transmission project to sell capacity into the sink location of that transmission project. Currently, the holder of existing UDRs and EDRs must elect the UCAP associated with the UDR or EDR they will use in the upcoming Capability Year. The quantity elected by these UDR and EDR rights holders is currently assumed as available capacity when determining minimum ICAP requirements.

Under this proposal, on August 1 prior to the applicable Capability Year, UDR and EDR holders will be required to submit distinct seasonal elections, one for the Summer Capability Period and one for the Winter Capability Period. These two separate election values may provide more accurate input of available capacity in the applicable season that can be reflected in the NYSRC IRM study.

UDRs and EDRs that elect to participate in the ICAP market, but do not offer capacity, may create a misalignment between the proposed seasonal requirements and available supply in a delivery month. To account for this potential misalignment, the NYISO has proposed a must offer requirement for holders of UDRs and EDRs and associated penalty if the holder of an External UDR or EDR fails to offer or certify UCAP associated with an External UDR or EDR that has not been returned to the NYCA in any ICAP Spot Market Auction during the subject Capability Period.

Capacity Accreditation Factors

CAFs reflect the marginal reliability contributions of resources participating in the ICAP market towards meeting the NYSRC resource adequacy requirements for the upcoming Capability Year based on the IRM study. The NYISO utilizes the final LCR case, which is derived from the IRM, as the starting point for calculating annual CAFs for each CARC. Currently, there is no seasonal reliability criteria established for the IRM study. Both the IRM and LCR final cases represent reliability criteria across two seasons at an annual 0.1 LOLE criteria. As annual CAFs are calculated using the final LCR case, annual CAFs reflect the marginal reliability values against the annual 0.1 LOLE criteria.

As only annual 0.1 LOLE is modeled in the IRM study, there is no stable criteria to calculate seasonal CAFs. Using the distribution of seasonal risk in the IRM model as the basis for seasonal CAFs could also introduce significant volatility in seasonal CAF values. For example, if only summer reliability risk is present in the IRM study (e.g., 2024-2025 Capability Year), under the winter seasonal CAFs, the perfect unit and the representative unit may both provide zero marginal reliability value. Also, if winter risk becomes the dominated risk, some CARCs, such as non-firm and solar, may have a seasonal CAF near zero. This would lead to adverse incentives in the market.

The NYISO has recommended retaining annual CAFs as they reflect the risk-weighted average of each CARC's seasonal resource adequacy benefits and provide a more reliable and predictable price signal for attracting an annual fleet, recognizing the difficulty of capacity to enter or leave the market for short durations of time. CAFs will reflect winter reliability value as winter reliability risk becomes more pronounced.

Seasonal Demand Curve Enhancements

The current seasonal ICAP Demand Curves account for the difference in seasonal availability of ICAP in the Spot Market Auctions. The NYISO uses seasonal capacity availability adjustments (i.e., the winter-to-summer ratio (WSR) and summer-to-winter ratio (SWR)) to determine the maximum clearing and reference point prices of the seasonal ICAP Demand Curves.

Seasonal NYCA Minimum ICAP Requirements derived from the IRM model directly represent the amount of capacity needed to maintain the NYCA system at the 0.1 event-days/year LOLE criteria, eliminating the need for seasonal capacity availability adjustments. Accounting for the difference in the seasonal availability of ICAP based on the IRM model results is a more accurate representation of future NYCA system needs in the upcoming Spot Market Auction timeframe. Therefore, the NYISO proposes to remove the WSR and SWR components of the denominators of the maximum clearing price and reference point price formulas of the seasonal demand curves.

Reliability Attribute-Based Capacity Pricing

The Reliability Attribute-Based Pricing project is one of the NYISO's prioritized market initiatives, aimed at enhancing the capacity market's ability to reflect transmission security needs. This initiative merges concepts from valuing transmission security and an attribute-based market design, offering a framework for considering additional reliability attributes in the future. Pricing transmission security explicitly may incent investment that supports reliability while delivering transparent and predictable market outcomes. This design directly supports the CMSR project's objective to accurately value resources according to their contribution to maintaining bulk system reliability. The NYISO currently plans to work on this project in earnest in 2027.

The prioritized Reliability Attribute-Based Capacity Pricing project seeks to align market incentives with the evolving reliability needs of the power system. As the grid evolves, the traditional ICAP market framework may fall short in valuing the specific attributes that contribute to system reliability, such as fast ramping, fuel assurance, and cold-weather performance. By explicitly compensating resources for these reliability-enhancing attributes, NYISO seeks that the right mix of technologies is available to meet both peak demand and operational challenges across seasons.

Additionally, this approach seeks to enhance transparency and investment signals for market participants. Current and future market participants may gain clearer guidance on which resource attributes are most valued, encouraging innovation and targeted development of resources that support grid resilience. It may also provide the NYISO with a framework to adapt more flexibly to emerging risks by adjusting attribute definitions and compensation mechanisms. Prioritizing this project would position NYISO as a leader in modern market design, capable of balancing reliability, affordability, and sustainability in a rapidly changing energy landscape.

Transmission Security Overview

Two tenets of power system reliability are resource adequacy and transmission security. As defined by the NYSRC, resource adequacy is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[19] The NYSRC defines transmission security as "the ability of the electric system to withstand disturbances such as electric short circuits or

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[19] New York State Reliability Council. (2023). Reliability Rules Manual Version 46. Retrieved from https://www.nysrc.org/wp-content/uploads/2023/07/RRC-Manual-V46-final.pdf

unanticipated loss of system elements.” [20]

Resource adequacy has been the historic focus of the ICAP market; beginning in 2019 the concept of TSL floor values was introduced. These TSL values are calculated from a deterministic analysis of the NYCA system’s ability to withstand the loss of one or more transmission elements. As a floor value, the TSLs prevent the LCRs from falling below the transmission security threshold. However, the introduction of TSLs as a floor value highlights that existing market signals may not directly incentivize transmission security needs. This suggests that different market outcomes may be realized if transmission security needs were directly accounted for and priced for in the ICAP market.

Transmission Security Pricing

NYISO could instead price transmission security explicitly and establish a dedicated transmission security auction that procures capacity specifically needed to meet transmission-constrained reliability requirements. This auction, co-optimized with the existing resource adequacy auctions, could primarily focus on resources located within zones that are transmission-constrained, e.g., currently Zones J and K. By separating this procurement from the broader ICAP market’s resource adequacy requirements, NYISO may send clearer price signals to resources that provide locational reliability value, encouraging investment in areas where transmission constraints are most acute.

A separate transmission security auction could operate alongside the existing ICAP market, with distinct clearing prices and obligations. Resources participating in the transmission auction would be compensated based on their ability to meet transmission security needs, such as satisfying N-1 or N-1-1 contingency criteria. This approach may allow NYISO to distinguish between capacity that contributes to system-wide resource adequacy and capacity that is critical for local deliverability.

Implementing separate auctions would require enhancements to NYISO’s market design, including new settlement rules, eligibility criteria, performance metrics, and separate demand curves. It would also necessitate coordination with transmission planning processes for alignment between market signals and infrastructure needs. However, the benefits may be substantial: clearer investment signals, improved reliability in constrained zones, and better alignment between market outcomes and physical system needs. This approach may also reduce reliance on administrative LCR floors and improve transparency in how transmission security is valued.

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[20] New York State Reliability Council. (2023). Reliability Rules Manual Version 46. Retrieved from https://www.nysrc.org/wp-content/uploads/2023/07/RRC-Manual-V46-final.pdf

Transmission Security Attribute

Before transmission security can be priced explicitly, the qualities of a resource that constitute the ability to provide transmission security need to be defined. This attribute of a resource could be based on the overall dispatchability of a resource. When a resource is able to satisfy resource adequacy requirements through their bid/schedule/notify obligations, a resource may satisfy transmission security requirements through their dispatchability by the NYISO during potential transmission security events. A resource's dispatchability might be able to be scored on a variety of capabilities including, but not limited to:

- Start-up time
- Ramp Rate
- Duration
- Fuel Firmness or dual-fuel capability
- Size relative to the Locality's largest contingencies
- Location relative to transmission constraints

A resource with a high degree of dispatchability may fully qualify to provide transmission security, while resources with less or no degree of dispatchability would qualify for partial or zero ability to provide transmission security.

Additional Attributes

The framework provided by an implemented transmission security-based market structure may provide an opportunity for the NYISO to review additional attributes for explicit pricing. There may exist additional attributes that are valued in the Energy or Ancillary Services Markets but may present a "missing money problem" (i.e., the energy and ancillary services revenues may not attract and retain Resources that could provide these additional attributes) and the need to maintain the reliability of the evolving grid may impact their consideration. Additional attributes may include, but are not limited to:

- Ramping
- Inertia
- Voltage Stability
- Black Start
- Quick Cycling (Quick Start-up, Short Minimum down-time)

This effort to explore additional reliability attributes could be a Phase 2 effort of the initial work to incorporate transmission security. Tentatively, the NYISO could only feasibly consider starting such a project in earnest in 2030. However, the NYISO and its stakeholders would work to determine if the ICAP market is an appropriate and efficient market to value identified reliability services. Some attributes may be more efficiently valued as an enhancement to the Energy or Ancillary Services markets. Some attributes may be more efficiently valued as a separate market services rate schedule, like current Voltage Support Service or black start procurement and compensation.

Improving Capacity Accreditation and Resource Adequacy Modeling

The NYISO has identified the need to explore adjustments to marginal capacity accreditation and resource adequacy modeling processes that may improve ICAP market stability, enhance transparency and predictability, and support more informed decision-making by market participants. Current approaches rely on annual LOLE-based metrics and a limited historical dataset, which can introduce volatility and reduce confidence in ICAP market outcomes. This initiative seeks to address these challenges through targeted enhancements. Adjustments could include, but are not limited to, adopting an alternative marginal capacity accreditation calculation, or utilizing additional historical input data into the resource adequacy model.

Reducing Variability in CAFs

CAFs are used to determine the marginal reliability that a resource contributes toward meeting system reliability requirements. The current CAF calculation can be sensitive to relatively small changes in the base IRM/LCR model used to calculate CAFs. Changes in CAFs from year to year can complicate market forecasting and investment decisions. Reducing variability in CAFs from year to year may contribute to maintaining confidence in the ICAP market capacity pricing.

One driver of the sensitivity in the current CAF calculation may stem from the use of the probabilistic LOLE. As a result, when resource performance assumptions or outage rates shift slightly, there may be a relatively large change in the marginal reliability contribution of a CARC, which may result in significant changes in CAF values. Such a change could have an amplified impact on emerging technologies such as storage and renewables, whose performance profiles vary seasonally and depend on weather conditions. As the resource mix evolves, these fluctuations may undermine the credibility of capacity pricing and could deter investment in technologies that are needed for system reliability and compliance with New York policies. To address this challenge, NYISO seeks to explore alternative reliability metrics such as expected unserved energy (EUE), which may provide a more stable and predictable CAFs because the EUE captures any reduction in outages from the incremental resource.

Utilizing additional historical input data in the IRM study may also help reduce year-to-year CAF variability. The IRM study currently uses a rolling 5-years of historical performance data when modeling internal NYCA resources. Rolling on and off a year of resource performance data impacts both the IRM and LCRs as well as CAFs. Utilizing more years of historical performance data may decrease some of the year-to-year variability in the IRM, LCRs, and CAFs. As part of this effort, the NYISO would work to evaluate the use and implications of additional historical input data in the IRM study.

These improvements aim to deliver transparent and predictable CAF values, enabling market participants to make informed decisions and supporting a durable ICAP market structure. Reducing variability in CAFs will enhance market efficiency, reduce administrative complexity, and align capacity valuations with actual reliability contributions.

Capacity Zone Redesign

The Capacity Zone Redesign project is a prioritized market initiative aimed at improving the structure and effectiveness of the ICAP market by redesigning how capacity zones are defined and utilized. This project originated a 2022 State of the Market Report recommendation, in which the MMU recommended that the NYISO implement more granular capacity zones and a dynamic process for updating the zones (Recommendation 2022-4).[21] Many elements of Recommendation 2022-4 were also included in the Granular Capacity Zonal Pricing Issue Discovery Report (December 2024), which outlined key considerations for a Capacity Zone Redesign effort.[22] NYISO currently plans to begin working on this project in earnest in 2028.

This project seeks to better reflect the evolving transmission constraints and locational reliability needs across New York State. As the grid transitions to accommodate more intermittent resources, electrification, and the increased proliferation of prosumers on the grid, the existing capacity zones may no longer accurately represent the geographic and operational characteristics of the system. Enhancing the zonal framework may improve price formation, provide more efficient capacity procurement, and better signal where new investments are needed to maintain reliability and meet New York policy goals.

Aligning capacity obligations and pricing with actual system constraints and resource deliverability

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[21] Potomac Economics. (2023, May 16). 2022 State of the Market Report for the NYISO Markets. Retrieved from https://www.potomaceconomics.com/wp-content/uploads/2023/05/NYISO-2022-SOM-Full-Report__5-16-2023-final.pdf

[22] New York Independent System Operator. (2025). Granular Capacity Zones Issue Discovery Final Report. Retrieved from https://www.nyiso.com/documents/20142/48542026/Granular%20Capacity%20Zones%20Issue%20Discovery%20Final%20Report.pdf/988bd383-2328-d36f-dbad-f833bec20725

may reduce uplift costs and improve transparency for market participants as transmission upgrades, offshore wind integration, and load growth patterns shift the reliability landscape. This project enables the NYISO to proactively adapt its market structure to future grid conditions, allowing the ICAP market to remain robust, fair, and aligned with both reliability and New York State's objectives.

Project Recommendations

The MMU's initial recommendation to pursue a refined capacity zone design originated from a concern that the current zonal framework may inadvertently create barriers to entry for new, efficient resources due to high interconnection costs, while simultaneously overcompensating existing resources in areas with intrazonal constraints. This misalignment can distort market signals and hinder optimal resource investment and retirement decisions. Addressing these inefficiencies could ultimately improve locational price signals and support system reliability.

Key objectives of a market design could include exploring alternatives to the deterministic test used in the New Capacity Zone (NCZ) study, modifying the frequency and flexibility of changing zonal boundaries, and restructuring the interrelationship and classification of capacity zones. These enhancements aim to preserve the strength of price signals of the capacity market while minimizing unpredictable market outcomes.

Deliverability Bottlenecks

Deliverability bottlenecks in the NYISO system arise when transmission constraints prevent capacity resources from being fully deliverable to load centers, even if they are technically available. These bottlenecks are often identified through Class Year Deliverability Studies and Expedited Deliverability Studies, which assess whether new or existing resources meet the NYISO Deliverability Interconnection Standard. When resources are deemed undeliverable, they may require System Deliverability Upgrades (i.e., transmission enhancements that enable full capacity delivery). These constraints can lead to "bottled" generation, where resources are physically unable to contribute to reliability due to transmission limitations.

To address these issues, NYISO periodically conducts NCZ Studies, which evaluate whether transmission interfaces between existing zones are constrained enough to warrant the creation of new zones. The 2023/2024 NCZ Study, for example, assessed six highway interfaces and found no constraints that would trigger a new zone, but it highlighted the importance of ongoing monitoring as system conditions evolve. These studies are closely tied to the DCR process so that capacity pricing reflects the cost of providing reliability, including the impact of transmission bottlenecks.

Import and Export Demand Curves

The NYISO could develop import and export demand curves to better reflect the locational value of capacity across transmission interfaces, as recommended by the MMU. These curves would represent the marginal reliability value of importing or exporting capacity between zones, particularly where transmission constraints limit deliverability. By explicitly modeling the price sensitivity of capacity flows across interfaces, NYISO could improve the efficiency of capacity procurement and send clearer signals to resources that support inter-zonal reliability. This approach may also help differentiate between capacity that contributes to system-wide resource adequacy and capacity that alleviates local transmission bottlenecks.

Import and export demand curves could be used to dynamically adjust capacity prices based on real-time or seasonal transmission conditions, improving locational accuracy and reducing price uncertainty. However, this would require changes to the LCR setting process and the spot auction clearing logic. By integrating these curves into the market design, the NYISO may better capture the reliability contributions of resources at the edges of constrained zones, improve investment signals, and reduce reliance on administrative deliverability tests.

Capacity zones play a critical role in establishing effective locational price signals. A well-designed zonal structure can help optimize resource entry and exit decisions to procure capacity efficiently and reliably across the NYCA. By exploring refinements to the zone-setting process, NYISO aims to enhance the overall efficiency and reliability of the ICAP market, aligning it more closely with evolving system needs and stakeholder expectations.

Review of Bifurcated Markets

Outside of the five efforts detailed above, none of the other design ideas explored as part of CMSR project have been prioritized for future projects. These ideas were not considered for prioritization due to a combination of the following: lack of stakeholder support, empirical evidence of implementation challenges with a design in neighboring control areas, and/or perceived difficulty in adapting design theory to a structured market design.

Bifurcated Capacity Markets: New vs. Existing Resources

Stakeholders requested that the NYISO consider a bifurcated capacity market for new and existing resources. To evaluate this market design concept, the NYISO contracted with FTI Consulting, which highlighted concerns with a market design that discriminates between market participants. The MMU also provided a detailed analysis of the bifurcated market design concept, which outlined advantages in maintaining an ICAP market based on a uniform clearing price.[23] NYISO concluded that a bifurcated market design is not suitable for the ICAP market because it may introduce significant risks to reliability, increase long-term consumer costs, and complicate market operations.

Design Complexity and Market Distortion

Implementing a bifurcated market design introduces significant complexity into NYISO's ICAP market operations. Differentiating between new and existing capacity requires changes to auction mechanics, settlement procedures, and contract structures. LSE obligations must be recalculated using weighted average pricing rather than simple megawatt-based metrics. This complicates hedging strategies and increases administrative overhead. Separate auctions or demand curves for each capacity type also require ongoing recalibration, adding to the burden.

Market distortions are another major concern. By capping prices for existing capacity, the market may inadvertently incentivize exports of lower-cost resources to neighboring regions with higher prices, while relying on imports that may be less reliable during regional shortages. This undermines the integrity of the resource adequacy framework and could lead to reliability risks, especially during peak demand periods or unexpected system stress.

Furthermore, bifurcated pricing can distort investment signals. Developers of new capacity may demand higher upfront payments, knowing their assets will eventually be reclassified and earn less. This could result in a steeper supply curve for new capacity, increasing procurement costs. Additionally, the design may bias procurement toward short-lived assets that maximize revenue during their "new" classification period, even if they are less efficient or more costly over time.

Short-Run vs Long-Run Tradeoffs

In the short run, a bifurcated market design may appear to benefit consumers by lowering payments to existing capacity resources. This reduction in producer surplus can translate into immediate cost savings, especially in markets with surplus capacity. However, these savings are often temporary and can mask deeper structural issues that emerge over time.

As existing capacity exits the market due to suppressed prices, the system becomes increasingly reliant on new capacity, which is typically more expensive to build and operate. This shift can lead to higher procurement costs in future auctions, eroding the initial consumer savings. Moreover, if the rate of

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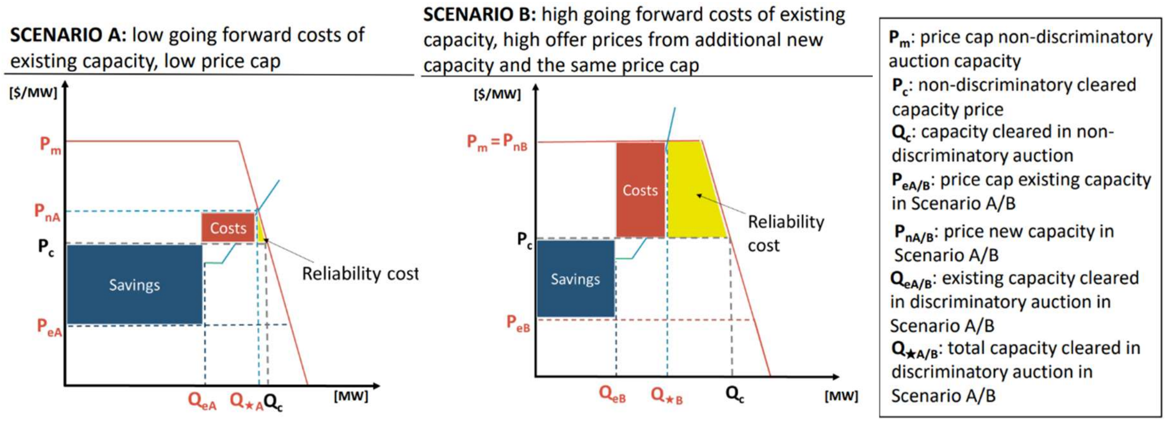
[23] Potomac Economics. (2025, May 22). *MMU CMSR Discussion*. Retrieved from https://www.nyiso.com/documents/20142/51574954/MMU%20CMSR%20%20Discussion%2005-22-25.pdf/07ad280f-78be-f858-d27c-ed6033a64a1f

new entry does not keep pace with the exit of existing resources, reliability risks may surface, particularly during periods of peak demand or unexpected system stress.

The long-run consequences also include diminished investment signals and distorted resource planning. Developers may hesitate to invest in long-lived assets if they anticipate future reclassification and lower earnings. This can skew the market toward short-duration or less efficient technologies, undermining the overall reliability and cost-effectiveness of the grid. Ultimately, while bifurcated pricing may offer short-term relief, it risks compromising the long-term health and resilience of the capacity market. Figure 12 provides an illustrative example of how initial savings from a bifurcated market structure in the short run can be eroded in the long run with greater economic and reliability costs.

Figure 12: Short Run (Scenario A) vs Long Run (Scenario B) tradeoffs of a discriminatory auction structure



Investment and Performance Incentives

A bifurcated market design can significantly weaken investment incentives by creating uncertainty around future revenue streams. Developers of new capacity may be discouraged from investing in long-lived assets if they expect their resources to be reclassified as "existing" and subject to lower payments after a few years. This undermines the economic rationale for building durable, high-performance infrastructure and may lead to underinvestment in critical capacity.

The design also risks distorting performance incentives. In a uniform market, capacity payments are tied to availability and reliability, encouraging resources to maintain high operational standards. However, if existing capacity receives lower payments regardless of performance, the incentive to invest in fuel security, maintenance, or upgrades diminishes. This could result in a degradation of resource quality and availability over time.

Moreover, bifurcated pricing may bias investment decisions toward short-lived or modular technologies that can maximize revenue during their "new" classification period. While these assets may be easier to deploy, they often lack the robustness and efficiency of longer-term solutions. This shift could compromise the long-term reliability and cost-effectiveness of the grid, especially as system needs evolve with electrification and climate goals.

Real-world Examples

The Belgian capacity market has implemented a bifurcated design since 2021, using a pay-as-bid structure with different price caps and contract lengths for new and existing capacity. Existing units face an intermediate price cap, typically one-third of the global cap, and are limited to one-year contracts. New capacity can secure contracts up to 15 years based on capital investment thresholds.[24] This structure has led to consistent exit of existing capacity and higher prices for new capacity, demonstrating the real-world impact of discriminatory pricing.

Spain operated a discriminatory capacity payment system from 2007 to 2018, offering administratively-set investment and availability payments only to newer or dispatchable technologies.[25] These payments were intended to reduce costs but ultimately contributed to financial stress for thermal generators, especially as renewables gained market share.[26] The inability of existing plants to exit without government approval led to legal challenges and strategic behavior, with generators signaling retirement to prompt government support.

California's resource adequacy framework lacks a centralized auction and has historically allowed price discrimination through bilateral contracting. New capacity has been procured under long-term contracts, while existing capacity often faces uncertain pricing and procurement gaps. This contributed to the retirement of over 10,000 MW of gas-fired generation between 2013 and 2020,[27] some of which was reversed or delayed due to reliability concerns. The California experience highlights how discriminatory procurement can undermine reliability and lead to unintended consequences.

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[24] European Commission. (2021). State Aid SA.100253 – Amendments to the Pan-European Guarantee Fund in response to COVID-19 (C(2021) 8494 final, Public Version). Brussels. Retrieved from https://ec.europa.eu/competition/state_aid/cases1/202205/SA_100253_C07C967E-0000-CB6D-B96D-37E507A96BEC_74_1.pdf

[25] Government of Spain. (2023). Draft Updated Integrated National Energy and Climate Plan 2023–2030. European Commission. Retrieved from https://commission.europa.eu/document/download/9ea170ec-fdce-49cb-9424-4ee95db33a4a_en?filename=EN_SPAIN%20DRAFT%20UPDATED%20NECP.pdf

[26] Enerdata. (2023, November 6). Spain rejects Endesa's request to close its Colón CCGT power plant. Daily Energy News. Retrieved from https://www.enerdata.net/publications/daily-energy-news/spain-rejects-endesas-request-close-its-colon-ccgt-power-plant.html

[27] California Independent System Operator (CAISO). (2024, November). Announced Resource Retirement and Mothball List [Excel spreadsheet]. Retrieved from https://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx

Conclusion

The CMSR project has identified a range of structural and operational challenges facing the ICAP market as it adapts to evolving reliability needs, resource mixes, and policy drivers. While the ICAP market has historically supported resource adequacy through transparent price signals, emerging risks such as winter reliability risks, transmission security constraints, and the increasing proliferation of state-sponsored resources have spurred a review of the capacity market design fundamentals. The CMSR project has explored a wide array of potential enhancements, including the following prioritized efforts: ICAP DCR Process and Methodology Improvements, Winter Reliability Capacity Enhancements, Reliability Attribute-Based Capacity Pricing, Capacity Zone Redesign, and Improving Capacity Accreditation and Resource Adequacy Modeling.

Through stakeholder engagement, the NYISO has prioritized a set of initiatives that aims to improve market efficiency, reduce administrative complexity, and better align capacity pricing with system reliability needs. While some market design concepts, such as bifurcated capacity markets, were ultimately not pursued due to concerns over feasibility and distorting market signals, their consideration has provided valuable insights to inform future market design considerations.

The NYISO remains committed to working collaboratively with stakeholders to implement the prioritized efforts so that the ICAP market continues to deliver durable, transparent, and economically efficient outcomes. The NYISO seeks to maintain a reliable grid while supporting investment in the resources needed to meet New York’s clean energy and reliability goals.

Appendix A Project Timelines and Prioritization Results

Project Timeline

Priority Effort	2025	2026	2027	2028	2029	2030
Capacity Market Structure Review	ID					
Winter Reliability Capacity Enhancements	MDC	DC	DEP			
ICAP DCR Process and Methodology Improvements		MDC	DEP			
Reliability Attribute-Based Capacity Pricing for Transmission Security (Phase 1)			MDC	DC	DEP	
Improving Capacity Accreditation and Resource Adequacy Modeling		SC	MDC	DEP		
Capacity Zone Redesign				MDC	SDS	DC
Reliability Attribute-Based Capacity Pricing for Additional Attributes (Phase 2)					CP	MDC
Demand Curve Reset	*DEP*		*SD*	*SC*	*DEP*	

Key

ID	Issue Discovery
SD	Study Defined
SC	Study Complete
CP	Market Concept Proposed
MDC	Market Design Complete
SDS	Software Design Specification
DC	Development Complete
DEP	Deploy

2026 Project Prioritization Results

At the July 30, 2025, Budget and Priorities Working Group meeting, the NYISO presented the results of the stakeholder survey and the NYISO scoring of the 2026 proposed market design projects.[28] The table below identifies the results of the stakeholder survey based on weighted ranking as well as the NYISO

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[28] New York Independent System Operator. (2025). Stakeholder Survey Results and NYISO Scoring of 2026 Proposed Market Projects. Retrieved from https://www.nyiso.com/documents/20142/52761841/02%20Project%20Prioritization%20Stakeholder%20Survey%20Results.pdf/41697fa1-026d-65f8-5b27-21f19e90ff74

ranking for each of the efforts assessed out of a total of 28 market design projects.

Project Name	Stakeholder Ranking	NYISO Ranking
Winter Reliability Capacity Enhancements	2	2
Evolving Resource Adequacy Structures	5	27
ICAP Demand Curve Reset (DCR) Process and Methodology Improvements	6	1
Improving Capacity Accreditation and Resource Adequacy Modeling	7	4
Reliability Attribute-Based Capacity Pricing for Transmission Security	13	4
Capacity Zone Redesign	24	12
Bifurcated Capacity Markets	27	27
Locational Marginal Capacity Pricing	Future Project	

Appendix B – Additional Reports and Presentations

Potomac Economics (Independent Market Monitor) Presentations

Title / Description	Date
Granular Capacity Zones (See Appendix of Presentation)	2024-08-29
Transmission Security in the Capacity Market MMU Recommendations	2024-09-24
MMU Comments on Valuing Transmission Security Issue Discovery Draft Report	2024-12-10
MMU Comments on Granular Capacity Zones Issue Discovery Draft Report	2024-12-10
MMU Analysis of Capacity Market Structure	2025-05-22

NYISO ICAPWG CMSR Project Presentations

Title / Description	Date
Project Kickoff	2025-01-22
CMSR	2025-02-04
CMSR	2025-03-03
CMSR	2025-03-26
CMSR	2025-04-01
ICAP Demand Curve Reset Process and Methodology Improvements	2025-05-22
New Supply Analysis	2025-05-22
ICAP Demand Curve Reset Process and Methodology Improvements	2025-06-17
Capacity Zone Redesign	2025-07-08
Reliability-Based Attribute Capacity Pricing	2025-07-08

FTI (Independent Consultant) Reports

Title / Description	Original Date[29]
EU Bifurcated Capacity Mechanisms (See Below)	2025-03-07
Demand Curve component of auction model (See Below)	2025-06-23
Potential for market power issues with a kinked demand curve (See Below)	2025-08-19
Concave Kinked Demand Curve Example (See Below)	2025-09-16

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[29] The independent consultant's reports have been revised for readability by a general audience since their original dates for posting with this report.

Bifurcated Capacity Markets in Europe: Belgium and Spain

Jason Mann, Tim Schittekatte and Anna Shukla[30]

March 7, 2025

In this note, we describe the Belgian and Spanish bifurcated capacity remuneration mechanisms. These two case studies are not "best practice examples." Rather, they exemplify some of the issues that can arise when trying to reduce the cost of a capacity mechanism by limiting payments to existing units. In the Belgium case, significantly higher capacity prices have been paid to new generation while existing generation has been exiting. How much of this is inefficient exit is hard to determine based on publicly available data.[31] In Spain, numerous existing units, mostly CCGTs, some of which previously received an administrative capacity payment, have been threatening to exit. This may be intended to put pressure on the government to increase their capacity payments and/or introduce a new capacity mechanism, rather than being driven by economics.

Historically, there has been typically a tension between Member States and the European Union ("EU") and the European Commission with regards to the introduction of capacity mechanisms, with the former being more eager to introduce a capacity mechanism than the latter. According to European legislation, security of supply remains a national matter and EU Member States have the right to determine their own electricity generation mix. On the other hand, the European Commission aims to safeguard a level-playing field between generators in different EU Member States that are competing against each other in the European Internal electricity market. Therefore, the European Commission has historically sought to limit EU Member States trying to introduce a capacity mechanism. Formally, all proposed capacity mechanisms in EU Member State must go through a thorough "State Aid" investigation before they can be introduced. This tension between the EU Member States and the European Commission has led to some of "quirks" in the designs of the European capacity mechanism. Since the European energy crisis ('21-'23), the European Commission has been more lenient in the approval of capacity mechanisms and the number of EU Member States with capacity mechanisms in place is projected to grow (e.g. Germany and potentially Denmark and the Netherlands).

I. Belgium

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[30] We are thankful to Yeray Perez for input on the Spanish case study.

[31] What we mean by "inefficient exit" here is capacity that would have not exited in case it would have received higher capacity payment (but still lower than the payment received by the most expensive new capacity awarded). In-the-money capacity can also exit due to other reasons such as environmental regulations. The exiting capacity numbers shown in Figure 3 of this note do not include any coal-fired generation (the last coal-fired generator exited in 2016 in Belgium) or nuclear capacity which has gradually been phased out for policy reasons.

Since 2021, Belgium has a pay-as-bid centralized capacity market in place. The key reason for the introduction of the capacity market has been to stimulate new investment to replace the large nuclear power fleet that has been planned to be gradually phased-out by the government (even though political uncertainty still exists around the phase-out). The capacity market is organized as two auctions per delivery year: one auction four years before ("Y-4") and another auction one year before ("Y-1") delivery.[32] There are different contract lengths available (from 1 year up to 15 years). The most popular contract length is 1 year as it is the only contract length available for existing capacity. The access to longer term contracts depends on the investment threshold in euro/kW.[33]

There is a capacity demand curve with a "global" price cap equal to the net CONE multiplied by an uncertainty factor ("A" in Figure 1 below).[34] There is some elasticity in the demand curve for the Y-4 auction with the capacity price cap equal to the net CONE ("B" in Figure 1 below) when the target volume would be cleared. There is a so-called intermediate price cap ("IPC") in place for existing units.[35] The IPC is calibrated based on "*the missing-money level of the worst performing technology class currently in the market.*" The rationale for the IPC provided by the Belgian Transmission System Operator ("TSO") Elia is a goal of reducing capacity market costs and mitigating market power.[36] As described later in this note, the IPC is typically about one third to half of the global price cap.

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[32] The volume allocated to the Y-1 auction shall be at least equal to "*the capacity required, on average, to cover the total peak capacity for less than 200 hours of operation per year*" (See the European Commission decision here: https://ec.europa.eu/competition/state_aid/cases1/202137/288236_2313671_226_2.pdf, ¶98 p. 21)

[33] See the European Commission decision here: https://ec.europa.eu/competition/state_aid/cases1/202137/288236_2313671_226_2.pdf, ¶138 p. 30.

[34] The reference technology to determine the net CONE can differ per auction but is typically demand response (see the European Commission decision here: https://ec.europa.eu/competition/state_aid/cases1/202137/288236_2313671_226_2.pdf, ¶23 p. 4). The uncertainty factor is typically around 1.5.

[35] The Belgian capacity market rules explicitly provide a procedure for an "IPC derogation". This allows a capacity supplier to submit a request to be allowed to bid above the IPC. This request needs to demonstrate that the missing money of the existing generator is greater than the IPC and needs to be approved by the national regulatory authority. This derogation is described in the Royal Decree of 4 June 2021. More information can be found in the following note: Belgium Government, 2021, IPC Derogation: Explanatory note, https://economie.fgov.be/sites/default/files/Files/Energy/Explanatory-note-IPC-Derogation-public-consultation-02022021-14022021.pdf

[36] Elia, 2019. CRM Design Note: Intermediate Price Cap, https://www.elia.be/-/media/project/elia/elia-site/public-consultations/20190913/20190913_design_note_intermediate_price_cap.pdf.

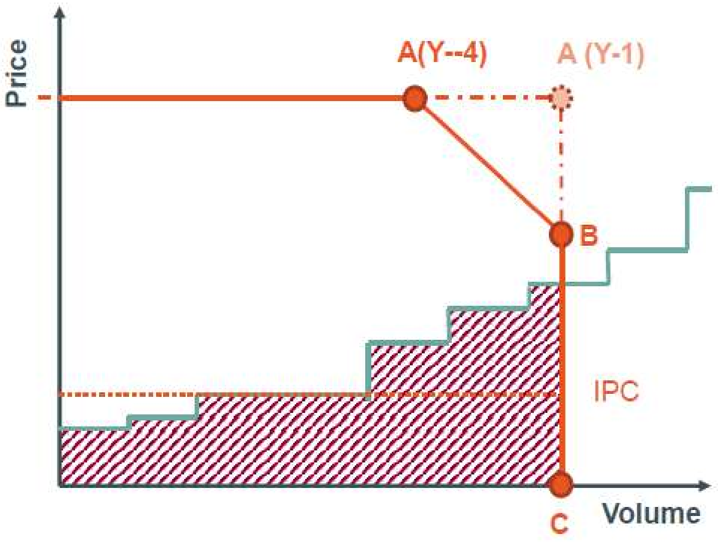

Figure 13: Demand curves and intermediate price cap ("IPC") for the Belgian Y-1 and Y-4 capacity auctions

The product sold in the capacity auction are reliability options with a stop-loss feature (i.e., the capacity seller cannot be asked to pay back more than what it received in the capacity auction).[37] The strike prices are administratively set (typically between 320 and 520 €/MWh) and can differ by technology.[38]

Four Y-4 auctions and one Y-1 auction have taken place thus far. We reviewed the reports[39] from these auctions to assess trends in capacity prices and contracted volumes across both new and existing capacity. Below the summary statistics for the capacity prices by auction are shown in Figure 2. As explained in the footnote, no capacity was procured in the Y-4 2026-2027 auction, so it is not shown.

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[37] There are also unavailability penalties in place. However, the sum of unavailability penalties and paybacks from the reliability option and the unavailability penalties shall not exceed the value of the annual capacity remuneration (see European Commission decision here: https://ec.europa.eu/competition/state_aid/cases1/202137/288236_2313671_226_2.pdf, ¶164 p. 34). This implies that in the worst case a resource being awarded a capacity contract breaks even.

[38] See European Commission decision here: https://ec.europa.eu/competition/state_aid/cases1/202137/288236_2313671_226_2.pdf, ¶154-156 p. 33

[39] See CRM auction results here: https://www.elia.be/en/grid-data/adequacy/crm-auction-results.

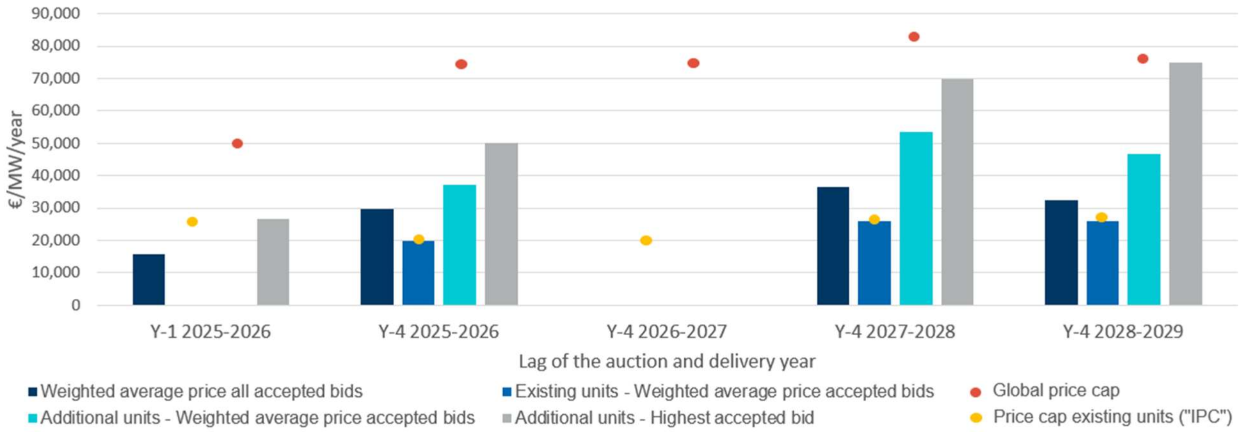

Figure 14: Capacity prices and demand curve parameters for the Belgian capacity auction. Notes: (1) In the Y-4 2026-2027 no capacity was cleared[40]; and (2) For the Y-1 2025-2025 only the weighted average price of all bids was provided - all accepted bids were under the price cap for existing units ("IPC").

We make three observations based on the figure above:

1. Due to the pay-as-bid nature of the auctions, the weighted average price of all accepted bids (first column) can be substantially lower than the most expensive accepted bid (last column).
2. Due to the price cap for existing capacity (the IPC), the weighted average price for cleared existing capacity (second column) can be substantially lower than the weighted price of cleared new capacity (third column). This is the case for the shown Y-4 auctions in which all existing capacity that participated in the auction was cleared.[41] For the Y-1 auction 374 MW of existing capacity was not cleared, instead sufficient capacity (including some "additional" capacity – see Figure 3 below) was cleared at prices below the IPC.
3. Due to the different timings of the auctions for the same delivery year, the capacity price for the same delivery year can be substantially different (see results for Y-1 2025-2026 vs Y-4 2025-2026).

In Figure 3, the volume cleared for different categories (existing, additional other[42] and additional new) is shown. Most new build capacity has been CCGTs in the earlier auctions and increasingly

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[40] In the Y-4 2026-2027 auction no capacity was contracted. Producers that held existing production capacity (amounting to a total of 6,682 MW) postponed their offers until the Y-1 auction. The volume of capacity relating to this so-called "Opt-Out IN" decision was deducted from the volume that was being auctioned off (demand curve of 6,417 MW). As a result, the demand for the year's Y-4 auction for 2026-2027 was fully covered. See here: https://uk.marketscreener.com/quote/stock/ELIA-GROUP-NV-SA-5989/news/Elia-CRM-auction-result-Y-4-for-2026-2027-published-on-elia-be-crm-42125630/.

[41] It is unclear whether this holds for Y-4 2026-1027 auction for which the capacity prices are not public.

[42] "Additional other" are existing units that committed to major upgrades and were not subject to the price cap for existing capacity.

battery energy storage ("BESS") in the later auctions. It can be seen that, as anticipated, for the delivery year 2025-2026 most existing capacity is cleared in the Y-1 auction[43] while most "additional" capacity is cleared in the Y-4 auction. Further, Figure 3 also shows that each year several hundred of MWs of existing capacity opted out from participating and retired. As mentioned in Footnote 2, none of the exiting capacity are coal-fired or nuclear units. The last coal unit was phased out in 2016 and exiting nuclear capacity is excluded from the numbers below.

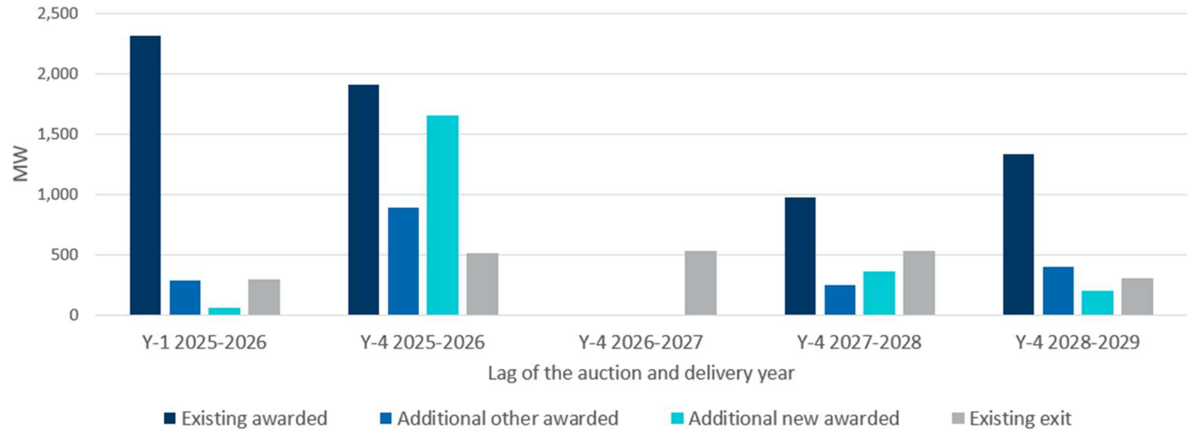

Figure 15: Cleared volumes and exiting of existing units in the Belgian capacity auctions. Notes: (1) In Y-4 2026-2027 no capacity was cleared; and (2) "Additional other" are existing units that committed to major upgrades and are not subject to the IPC.

Considering these auction results, we have two comments that are pertinent with regards to the potential for inefficient exit in Belgium due to its bifurcated capacity market.

First, for each Y-4 auction between 300-530 MW of existing capacity opted out of the capacity auction and retired. At the same time, for each of those auctions the weighted average bid price of the cleared "additional" capacity was substantially higher than the weighted average bid price of cleared existing capacity (87%, 107% and 81% higher for the delivery years 2025-2026, 2026-2027 and 2027-2028, respectively), with the latter being very near to the IPC in all auctions. It is not known whether without the IPC the retiring capacity would have participated in the capacity auction and, if so, whether their bids would have been lower than (some) of the accepted bids for "additional" capacity. However, considering that the highest accepted bid for "additional" capacity was threefold or more

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[43] Including for the first time in the case of the Belgian capacity mechanism foreign capacity participated and 1,260 MW of foreign capacity cleared (976 MW from the Netherlands and 284 MW from Germany). All the cleared foreign capacity was existing capacity.

the IPC, it is not unlikely that had existing plant been allowed to bid in an unrestricted fashion then they may have been more competitive than some new plants and hence not exited the market (reducing the very high prices for some new capacity).

Second, the 374 MW of existing capacity (bidding below the IPC) that did not clear in the Y-1 auction for 2025-2026 would have been cleared if it would have participated in the Y-4 auction. More research would be needed to determine the reasons some of the existing capacity did not participate in the Y-4 auction but instead waited for the Y-1 auction for the same delivery year (the same can occur for the 2026-2027 delivery year as a large share of existing capacity opted to wait for the Y-1 auction). Among potential reasons are market participants awaiting how relevant regulations and/or overall market dynamics evolve.

II. Spain

Spain is proposing a new capacity market to enhance the security of its electricity supply and support the integration of a larger variety of energy sources. The plan to introduce a capacity market was already in place before the black-out of the Iberian Peninsula on 28 April 2025. The previous capacity mechanism, in place from 2007-2018, compensated existing and new capacity differently.

Spain first introduced a capacity mechanism in 1998 after electricity generation was liberalized. The original 1998 scheme consisted of administratively determined "capacity payments" for all generation units.[44] In 2007 this capacity payment scheme was revised with the intent of reducing its costs. The new mechanism from 2007 onwards had two components: an "Investment Payment" and an "Availability Payment."[45]

The Investment Payment originally provided for a payment for 10 years that was made only available for power plants built after 1998. In practice, only CCGTs, a few hydro units and some coal-fired power plants received the Investment Payment.[46] The Investment Payment was subsequently extended up to 20 years for some generation units.[47] Eligibility for Investment Payments was phased-

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[44] Subject to a minimum running hours threshold. Generations units covered by a renewable support scheme was later excluded from the capacity payment.

[45] A detailed summary of how this mechanism evolved from 2007 can be found here (in Spanish): https://energy.ec.europa.eu/system/files/2023-11/01_PlandeImplementacion_ES_0.pdf

[46] Coal-fired power plants were eligible under the condition that they invested in technology to reduce their impact on local air pollution after 1998. The Investment Payments of these coal plants were typically lower than for new CCGTs.

In 2013 the magnitude of Investment Payments was reduced but the duration was extended calculated by a formula depending mostly on how many years a generation unit had already received a capacity payment by that time. The newer a unit, the longer the extension of the coverage by the Investment Payment. The longest possible extension was for units entering in 2013 that instead of 10 years were receiving Investment Payments for 20 years. See Article 7 (in Spanish) of https://www.boe.es/buscar/pdf/2013/BOE-A-2013-7705-consolidado.pdf out for new generation built after 2016, but grandfathered for those that were built before (as long as they were built after 1998). It is estimated that by 2021 around 70% of Spanish CCGTs were no longer entitled to their Investment Payment.[48] The Availability Payments were only in place between 2012 and 2018, and only paid to dispatchable generation technologies. The Availability Payment was calculated based on an administrative price per MW multiplied by a historical de-rating factor per technology. In 2018, a CCGT received around 10 k€/MW in Investment Payments and 5 k€/MW in Availability Payments. It is noteworthy that even before these payments were eliminated, they were very low by NYISO standards.

Currently, Spain is expected to face tighter capacity margins in the future:

1. Excess capacity in the Spanish system have been decreasing due the closure of old coal plants. In 2020 the government approved the phase-out of seven of the fifteen functioning coal-fired thermal plants at that time. The four companies that owned the plant – Naturgy, Endesa, Viesgo and Iberdrola – stated that they ceased operations of these power plants to avoid violating a European environmental directive forcing such plants to adopt technology to clean up the gases they emit.[49] In 2024, the government approved the closure of the largest coal plant (1,463 MW) by August 2024.[50] Spain aims to phase out coal power by 2030.
2. The nuclear fleet (7,123 MW) is expected to gradually commence decommissioning in 2027.
3. There is a risk of droughts reducing hydropower generation, which is a key part of Spain's electricity mix. In a wet year hydro generation can represent over 15% of annual generation, which is reduced to around 6% in a dry year.[51]

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[48] See https://timera-energy.com/blog/value-drivers-for-spanish-ccgts/

[49] See https://english.elpais.com/economy_and_business/2020-06-29/spain-to-close-half-its-coal-fired-power-stations.html. At the same time also domestic coal mines were closed and coal-fired power plants supplied by those domestic mines lost their rights on running a minimum number of hours because they were burning domestic coal.

[50] See https://www.enerdata.net/publications/daily-energy-news/spain-approves-closure-14-gw-coal-fired-plant-conditions.html

[51] For example, in 2022 amid the European energy crisis, there were droughts in Europe leading to record-low hydro production when the system was already tight due to lower than usual gas supplies (See https://www.spglobal.com/market-intelligence/en/news-insights/articles/2023/5/european-hydro-producers-face-droughts-without-cushion-of-sky-high-power-prices-75859964)

4. Spain has currently very limited BESS capacity installed. The Government considers the addition of more BESS plants to be a requirement in order to continue integrating renewable plants.[52]

5. CCGT currently provide most of the system firm capacity, however CCGT remains the marginal technology, and most plants have been barely recovering their going-forward fixed costs,[53] given the absence of scarcity related price spikes. A significant part of CCGT capacity has been mothballed due to profitability concerns. Market exits were historically subject to an administrative permit, but this requirement has been challenged in court. CCGT owners have been warning they may start decommissioning plants unless the Government approved a capacity payment.

While CCGTs have struggled to cover their going-forward fixed costs in recent years, the government has not always been willing to allow the CCGT plant owners to close their plants which, in turn, has led to litigation. For example, in 2015 the Spanish government refused to allow Endesa to close a CCGT plant. Other companies have applied to the Ministry of Energy to close thermal power plants. For example, Iberdrola had received the approval to shut down its Castellon CCGT plant, but eventually decided to keep it operational.[54] In 2017, the first and, so far, only CCGT was closed after approval of the government.[55] This was a new plant whose Investment Payments had ended but was still receiving Availability Payments. In the same year the utility Naturgy wanted to close five of its CCGTs because anticipated revenues did not suffice to make their continued operation economic (Availability Payments were still in place for those units but these were low as described above). It took Naturgy more than five years between its initial request and receiving a decision of the Spanish court allowing them to mothball these power plants.[56]

Even though Naturgy had the right to close the CCGTs, so far, it has not closed them. This failure to close the plants suggests that perhaps the retirement notices were strategic, intending to encourage the government to provide capacity payments even though the plants were economic. Finally, in 2024

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[52] One peculiarity of the Spanish system is that fast frequency services (so-called "Frequency Containment Reserves"), which are typically an important revenue source for BESS, are not subject to market-based procurement (while this a market-based service in nearly all EU countries). Instead, conventional units are required to provide these fast frequency services and are not remunerated for it.

[53] A source from 2017 estimates that some 80 percent of CCGT power plants would have been unable to recover their fixed cost on wholesale power markets without capacity payments (See https://ieefa.org/resources/ieefa-europe-legal-challenge-spains-capacity-market-payments-well-founded)

[54] See https://www.enerdata.net/publications/daily-energy-news/spain-rejects-endesas-request-close-its-colon-ccgt-power-plant.html

[55] This CCGT was operational for less than fifteen years; it came into service in 2003. See https://especiales.eldiario.es/los_excesos_del_gas/pagina4_en.html

[56] See https://uk.marketscreener.com/quote/stock/NATURGY-ENERGY-GROUP-S-A-74206/news/Naturgy-gets-top-Spanish-court-s-nod-to-mothball-gas-plants-45301476/

Iberdrola announced its intent to close seven CCGTs in 4-5 years.[57] Some commentators argue that the strategy of the companies behind the applications for closure of their CCGTs, or the announcements to do so, is to put pressure on the government to reinstate a capacity mechanism.

Potentially due to the risk that a large share of the CCGT fleet would close, in December 2024 a new Spanish capacity mechanism has been proposed by the Ministry of Energy which was under public consultation until the end of January 2025. Capacity prices would be set by auctions. Within the same "main" auction, existing and new units would be competing in the auction but contracts with different durations will be offered with longer contracts only awarded to new units. There would potentially be price discrimination between new and existing capacity under this design, by limiting the capacity of existing capacity that can take part in the "main" auction and the organization of separate "adjustment" auctions for existing capacity only.[58] The law that thermal capacity is not allowed to exit without consent from the government is currently still in place. Since the Iberian black-out, very limited information has been published indicating progress about the introduction of a capacity markets and its potential design features.

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[57] See https://renewablesnow.com/news/iberdrola-to-close-gas-fired-plants-in-spain-in-4-5-years-report-855432/

[58] More information can be found https://www.vectorenewables.com/en/blog/the-capacity-market-in-spain-regulatory-update-and-outlook-for-storage and https://e-greenify.com/news/3161/.

Demand Curve Concepts for a Capacity Market Auction Model

Scott Harvey, Tim Schittekatte, Victoria Lorvig and Jason Mann

June 23, 2025

The NYISO has described a concept being considered for a capacity market auction based on a state-wide demand curve, rather than local requirements.

We have thought about this and our conceptualization of this design has three elements:

1. The NYISO assigns load to bubbles connected by pipes with limited transmission;
2. There would be a demand curve in each bubble;
3. Bubble demand curves would be based on bubble load, not on a local capacity requirement (load – import capability).

FTI’s understanding is that this design would differ from the current local capacity requirement design in that the capacity cleared against the bubble demand curve would not need to be located in the same bubble. The demand curve load could be met by capacity in other bubbles if there is sufficient transfer capability. Hence, locational outcomes would be determined in the auction model taking account of transmission constraints and congestion (albeit in a simplified way, i.e. no transmission constraints within bubbles are considered and transfer capacities between bubbles are approximated). It seems to us this design would be in the spirit of the dynamic reserve design being developed for NYISO energy markets that allows unused transmission to meet reserve requirements.

We illustrate our understanding of how this would work with a simple two zone model and three cases. These initial cases assume that there is no nesting of zones or combined zones in the auction model, while the Local Capacity Requirement models include nested zones. We see that this approach could lead to unintended consequences.

For each case we assume the following parameters that remain constant:

- 5000MW load zone A and 5000MW load zone B.
- 2000MW transfer capability between the zones.
- $5000/MW-month for demand curve reference price in both zones.

- a zero-crossing point to be determined as 110% of the demand curve reference price implying a zero price at 5500MW.
- a price cap at $7500/MW-month which is reached when the cleared capacity is lower than or equal to 4750MW.

Case 1 - Balanced Capacity Case

We assume that 6000MW of capacity is offered at zero in Zone B and 4500MW offered at zero in Zone A.

A. Auction Model

Because the demand curves are the same in Zone A and Zone B, there would be 750MW of imports into Zone A from Zone B in the welfare maximizing market solution. The transmission constraint would not bind and the price set by the demand curve would be the same in the two zones with 5250 MW clearing in each zone at $2,500/MW-month. This is illustrated in Figures 1 and 2 below.

Figure 1: Capacity market clearing in Zone A under the Auction Model in the Base Case

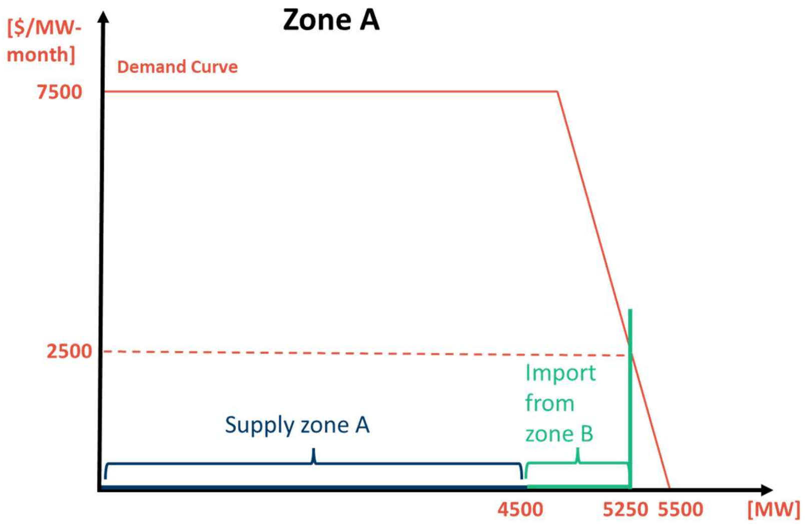
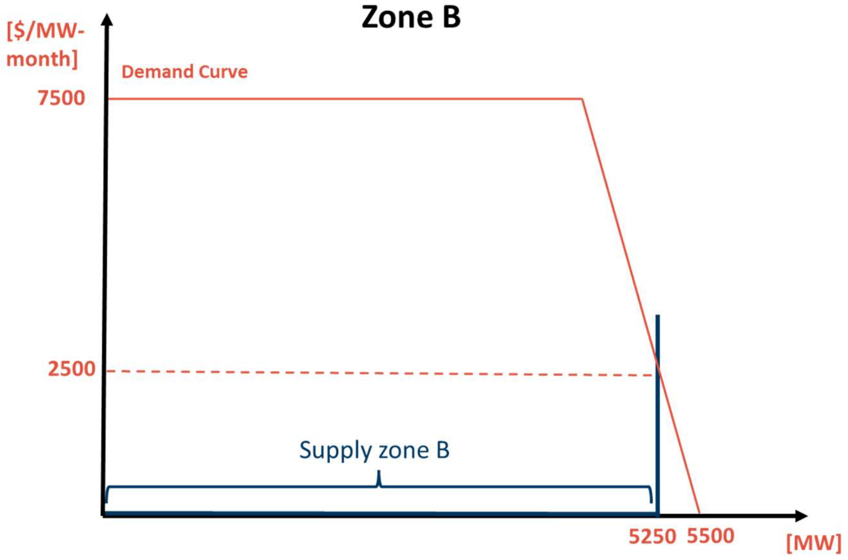


Figure 2: Capacity market clearing in Zone B under the Auction Model in the Base Case



In Table 1 we calculate the cost to load in both zones. The average capacity cost equals $2,625/MW-month in both zones which is slightly higher than the clearing price of $2,500/MW-month for generation as more generation (5,250MW) is cleared than there is load (5,000MW).

Table 1: Cost to load in each zone under Auction Model in the Base Case

	Zone A			**Zone B**		
	$/MW- Month	*Quantity*	*$ Overall*	*$/MW-Month*	*Quantity*	*$ Overall*
Load Payment for Capacity	$2,500	5,250	$13,125,000	$2,500	5,250	$13,125,000
Final Average Load Prices	**$2,625**	**5,000**	**$13,125,000**	**$2,625**	**5,000**	**$13,125,000**

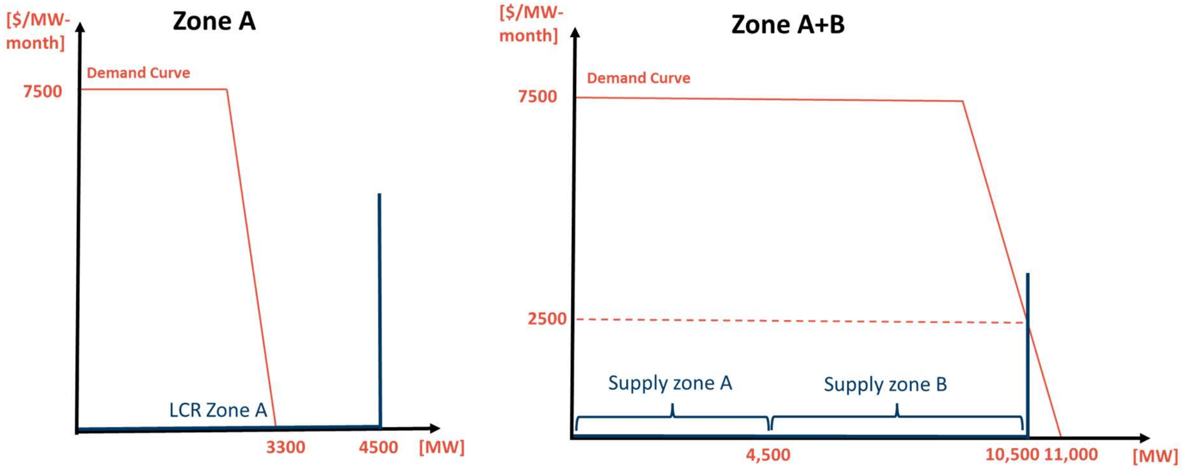
B.

Local Capacity Requirement model

The Local capacity requirement for Zone A would be 3000 MW (5000MW - 2000MW import capability). The zero-crossing point would be 3300 MW. With 4500 MW of capacity offered in Zone A and a price of zero, the price for Zone A capacity would be zero.

Zone A is nested within a combined A and B zone. The combined Zone A and B demand curve would have a 10,000 MW requirement with an 11,000 MW zero-crossing point. 4500 MW in Zone A would clear plus 6000 MW in Zone B. The clearing price for the combined zone A and B would be $2500/MW-month. The combined A and B Zone price would cascade to set the Zone price which could not be lower than the combined Zone A and B price. We illustrate the market clearings in Figure 3.

Figure 3: Capacity market clearing in Zone A and Zone A+B under the LCR model in the Base Case



In Table 2 we calculate the cost to load in both zones. We assume that the cost of the excess capacity purchased for the combined region (500MW) is shared between the consumers in both zones.

Table 2: Cost to load in each zone under a nested LCR Model in the Base Case

	Zone A			**Zone B**		
	$/MW- Month	*Quantity*	*$ Overall*	*$/MW-Month*	*Quantity*	*$ Overall*
Load Payment for In-Zone Capacity	$2,500	3,000	$7,500,000	$2,500	5,000	$12,500,000
Load Payment for Import Capacity	$2,500	2,000	$5,000,000			
Excess demand	$2,500	250	$ 625,000	$2,500	250	$ 625,000
Final Average Load Prices	**$2,625**	**5,000**	**$13,125,000**	**$2,625**	**5,000**	**$13,125,000**

We see that in this example the auction model and the Local Capacity Requirement model yield the same outcomes in terms of capacity clearing volumes, capacity pricing outcomes, and cost to load.

Case 2

We now assume that there is 7250 MW of capacity offered at zero in Zone B and 3000 MW offered at zero in Zone A. The other parameters remain the same as in Case 1.

A. Auction Model

2000 MW of imports would clear into Zone A, so there would be 5000 MW of total supply in Zone A. The auction would clear at reference price of $5000/MW-month in Zone A. Zone B would have 5250 MW of supply left. The auction would clear on the demand curve for Zone B at a lower price than in Zone A, i.e. $2500/MW-month. We will initially assume that the auction engine would simply clear Zone A and B, and not clear a combined Zone A and B. We think this is consistent with the initial view of this design not including a nested design. This is illustrated in Figures 4 and 5 below.

Figure 4: Capacity market clearing in Zone A under the Auction Model in Case 2

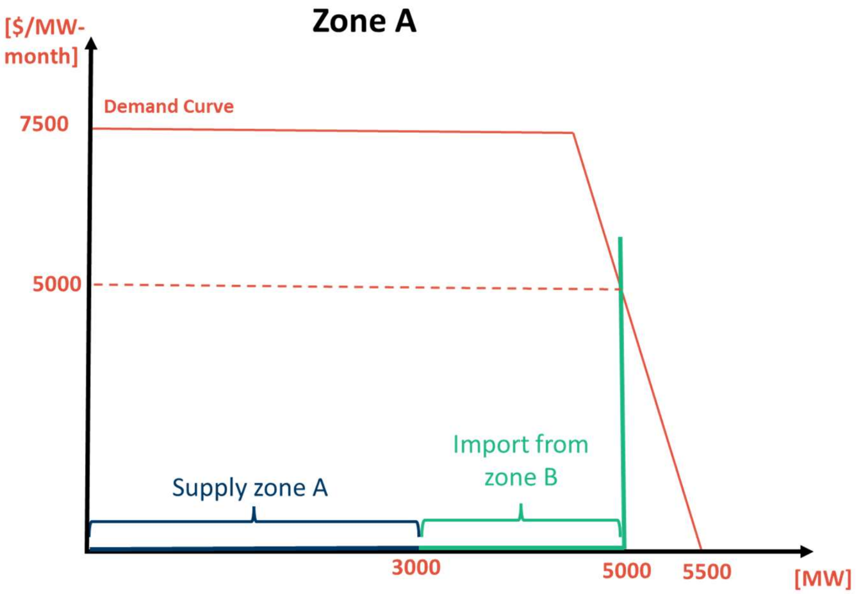
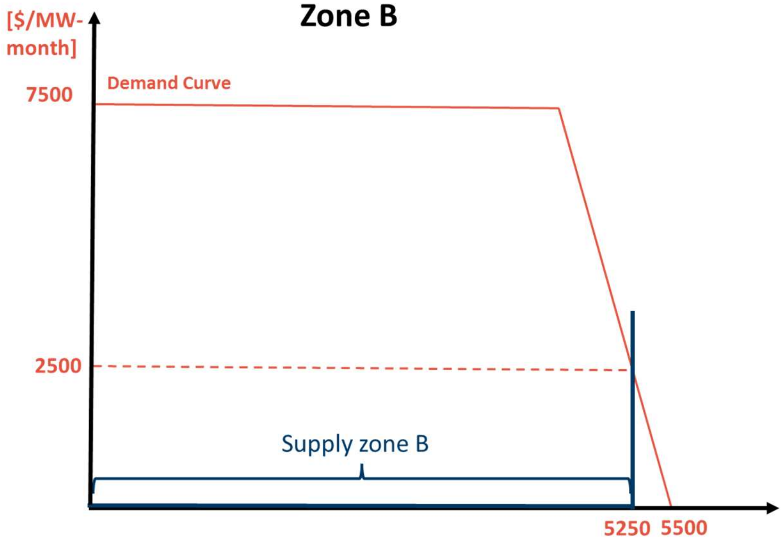


Figure 5: Capacity market clearing in Zone B under the Auction Model in Case 2



Generation in Zone A would be paid $5000/MW-month. Generation in Zone B would be paid $2500/MW-month.

In calculating the cost of capacity to load there would be capacity market congestion rents on capacity purchased in Zone B and sold into Zone A to be allocated. The congestion rents equal the transfer capacity multiplied by the price difference between the zones ($2,500*2000MW= $5,000,000). Since Zone A load pays congestion charges on capacity imported from Zone B, a typical design would allocate the congestion rents to load in Zone A. With such a design the average capacity charge paid by Zone A load would fall from the $5,000/MW-month paid to Zone A generators to an average price of $4,000/MW-month. The calculations are shown in the Table 3 below.

Table 3: Cost to load in each zone under the Auction Model in Case 2

	Zone A			**Zone B**		
	$/MW-Month	*Quantity*	*$ Overall*	*$/MW-Month*	*Quantity*	*$ Overall*
Load Payment for Capacity	$5,000	5,000	$25,000,000	$2,500	5,250	$13,125,000
Congestion Rent Income	$2,500	2,000	$5,000,000			
Final Average Load Prices	**$4,000**	**5,000**	**$20,000,000**	**$2,625**	**5,000**	**$13,125,000**

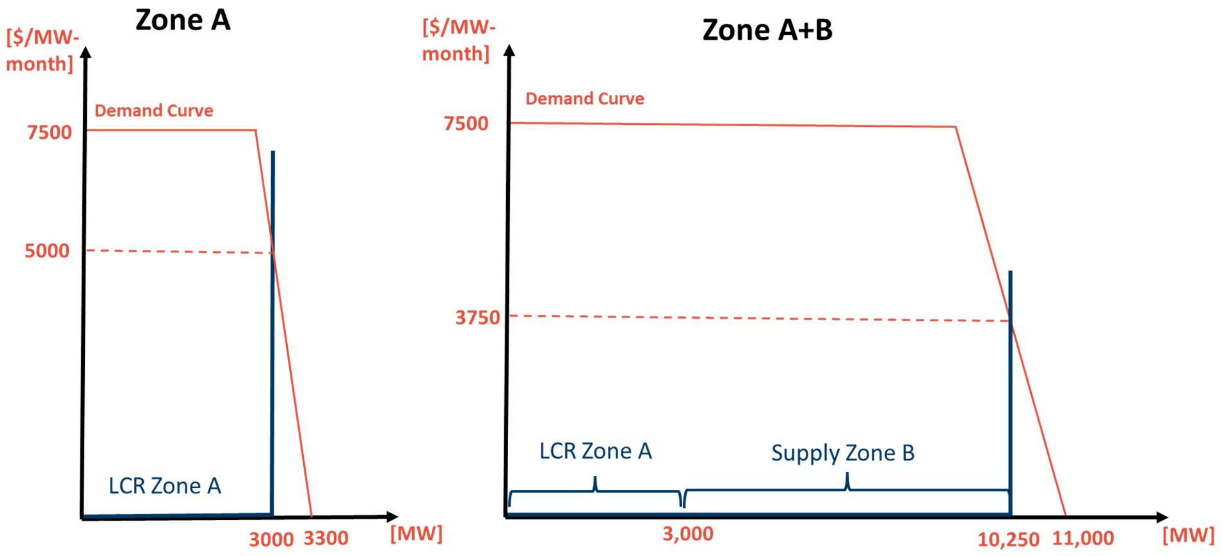
B.

Nested Local Capacity Requirement model

The Zone A local capacity requirement would be 3000 MW. The zero-crossing point would be 3300 MW. The 3000 MW capacity offered in Zone A would clear at the reference price of $5000/MW-month.

3000 MW of capacity would clear in Zone A and 7250 MW supply would be available in Zone B. The combined A and B supply would be 10,250 MW. The zero-crossing point of the combined Zone A and B demand curve would be 11,000 MW. The clearing price would be $3750/MW-month. This is illustrated in Figure 6 below.

Figure 6: Capacity market clearing in Zone A and Zone A+B under the LCR model in Case 2



Assuming the cost of the capacity in excess of the target quantity (250MW) is split between Zone A and B, the consumer payments in both zones are displayed in Table 4 below.

Table 4: Cost to load in each zone under a nested LCR Model in Case 2

Zone A	**Zone B**

	$/MW- Month	*Quantity*	*$ Overall*	*$/MW-Month*	*Quantity*	*$ Overall*
Load Payment for In-Zone Capacity	$5,000	3,000	$15,000,000	$3,750	5,000	$18,750,000
Load Payment for Import Capacity	$3,750	2,000	$7,500,000			
Excess demand	$3,750	125	$ 468,750	$3,750	125	$ 468,750
Final Average Load Prices	**$4,593.75**	**5,000**	**$22,968,750**	**$3,843.75**	**5,000**	**$19,218,750**

We see that in this example the Auction Model and the Local Capacity Requirement Model yield different outcomes in terms of both capacity prices for generation in Zone B and cost to load in Zone A and B. Under the Auction Model with no nesting, the price of capacity in Zone B is very low, potentially sending a price signal for exit. The nested Local Capacity Requirement model on the other hand sets a higher price for the combined Zone A and B region, which overall has a much tighter supply than Zone B.

This difference in design only affects prices in this example because all of the supply is assumed to submit price-taking offers. However, the Auction Model might not clear supply with non-zero offer prices, such as possibly demand response or imports, in Zone B that would be cleared in the nested Local Capacity Requirement model. Moreover, the Auction Model price outcomes would send a lower price signal for the retention of capacity in Zone B. The crux of the difference is whether the Auction Model should clear more capacity in a combined A-B region if less capacity is cleared in Zone A.

Under the Local Capacity Requirement model the load in both Zone A and B pay more than under the Auction Model. This is a result of the clearing of a combined Zone A and B in the Local Capacity Requirement model and the higher price in the combined A-B region than in a separate Zone B.

Case 3

This case is different from Case 2 in that 7250 MW is offered at zero in Zone B and 2750 MW is offered at zero in Zone A. Thus, supply offered in Zone A is less than in other cases and the overall amount of supply available in Zones A and B combined is less. The other parameters remain the same.

A. Auction Model

5250 MW of capacity clears in Zone B and 4750 MW of capacity clears in Zone A. The amount of capacity cleared in A is constrained by the transmission limit between Zone B and A. The clearing price is above reference price in Zone A, i.e. $7500/MW-month. The price in Zone B is $2500/MW-month (the same as in case 2). This is illustrated in Figures 7 and 8.

Figure 7: Capacity market clearing in Zone A under the Auction Model in Case 3

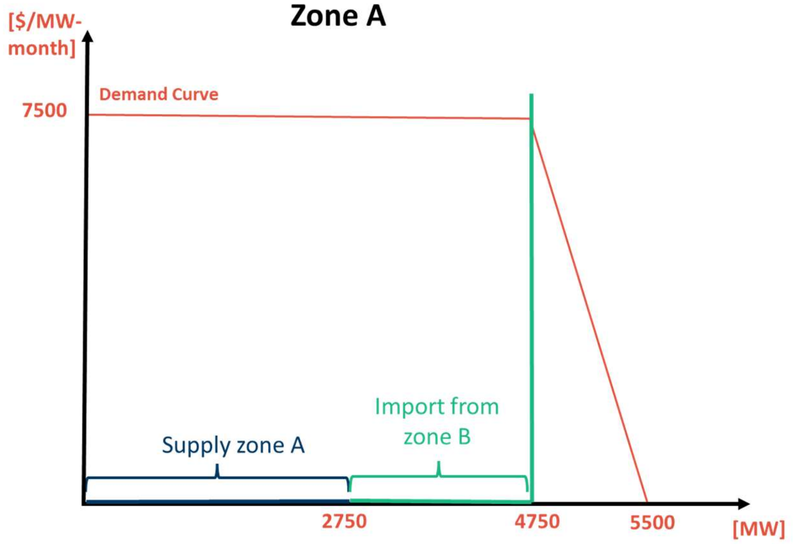
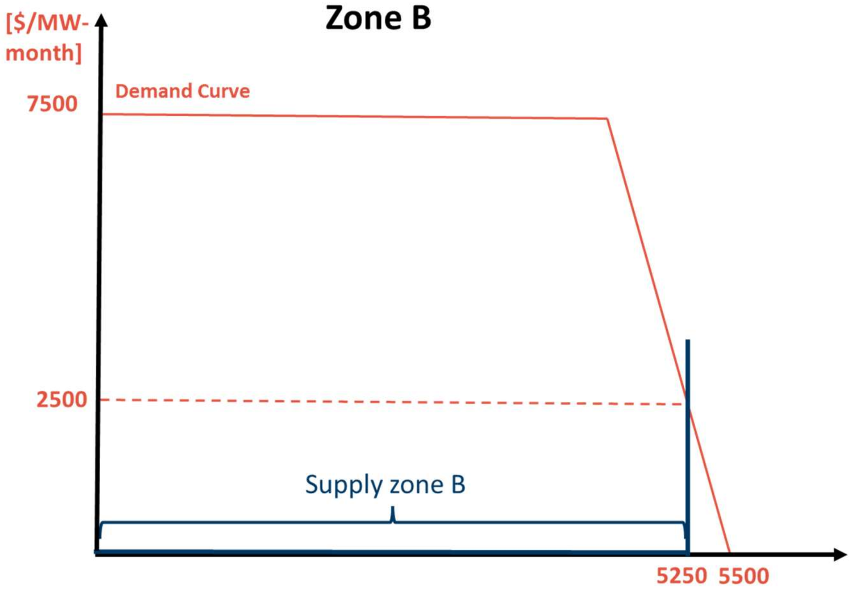


Figure 8: Capacity market clearing in Zone B under the Auction Model in Case 3



Generation in Zone A would be paid $7500/MW-month. Generation in Zone B would be paid $2500/MW-month.

There would be capacity market congestion rents on capacity transfers between Zone B and Zone A to be allocated. If these rents were allocated to load in Zone A on the basis that Zone A load paid the congestion charges, the average capacity charge for Zone A load would be $5,125/MW-month, while the charge to Zone B load would be $2,625/MW-month. The cost to load is shown in Table 5.

Table 5: Cost to load in each zone under the Auction Model in Case 3

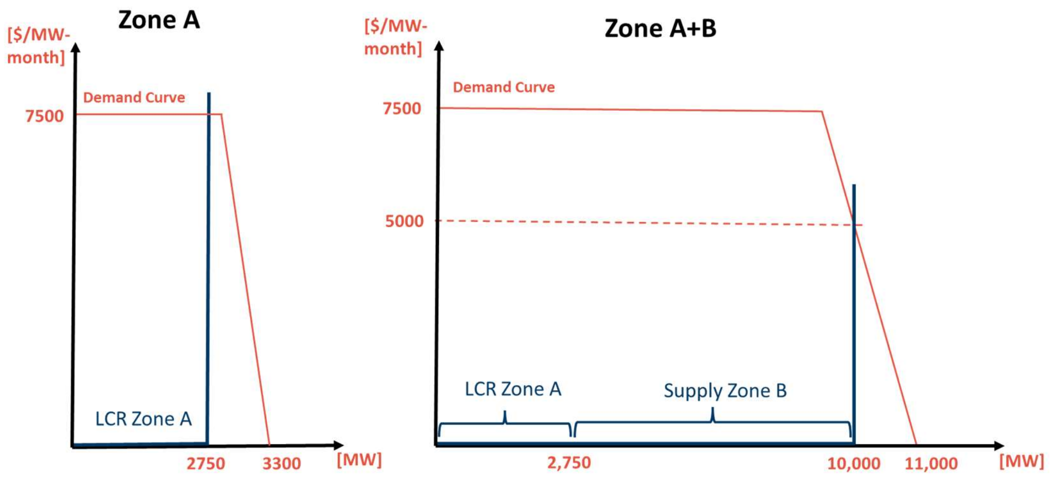
	Zone A			**Zone B**		
	$/MW- Month	*Quantity*	*$ Overall*	*$/MW-Month*	*Quantity*	*$ Overall*
Load Payment for Capacity	$7,500	4,750	$35,625,000	$2,500	5,250	$13,125,000
Congestion Rent Income	$5,000	2,000	$10,000,000			
Final Average Load Prices	**$5,125**	**5,000**	**$25,625,000**	**$2,625**	**5,000**	**$13,125,000**

B. Local Capacity Requirement model

In this case, there would be 2750 MW of capacity offered in Zone A with an local capacity requirement of 3000 MW. Capacity in Zone A would clear at the price cap of $7,500/MW-month.

2750 MW of capacity would clear in Zone A and 7250 MW of additional capacity supply would be available in Zone B, with 10,000 MW clearing, relative to the zero-crossing point of the combined demand curve at 11,000 MW. The clearing price would be the reference price, i.e. $5000/MW-month. This is illustrated in Figure 9.

Figure 9: Capacity market clearing in Zone A and Zone A+B under the LCR model in Case 3



There would be no demand curve excess supply for the combined A-B region with a cost to be allocated. The cost to load for consumers in Zone A and Zone B is shown in Table 6.

Table 6: Cost to load in each zone under a nested LCR Model in Case 3

	Zone A			**Zone B**		
	$/MW- Month	*Quantity*	*$ Overall*	*$/MW-Month*	*Quantity*	*$ Overall*
Load Payment for In-Zone Capacity	$7,500	2,750	$20,625,000	$5,000	5,000	$25,000,000
Load Payment for Import Capacity	$5,000	2,250	$11,250,000			
Final Average Load Prices	**$6,375**	**5,000**	**$31,875,000**	**$5,000**	**5,000**	**$25,000,000**

As in Case 2, we see in this

example that the Auction Model and the Local Capacity Requirement Model yield a different outcome for generation and load in Zones A and B. The price of capacity is $7500/MW-month in Zone A with either capacity market design, but the Auction model with no nesting yields a low price for capacity in Zone B ($2500/MW-month) despite that fact that capacity for the combined region exactly equals the target. This low price in Zone B could fail to retain capacity whose exit would create a situation in which there was not enough capacity to meet load in the combined A-B region. The Auction Model with no nesting could also fail to clear demand response or imports in Zone B with offer prices between $2500 and $5000/MW-month, despite the fact that their exit would create a capacity shortage for the combined A-B region.

The Auction Model without nesting (3A) also sends a low capacity price signal for load in Zone A relative to the nested Local Capacity Requirement model, with a capacity price of $5,125 in Zone A under the Auction model with no nesting compared to $6,375 under the nested Local Capacity Requirement Model (3B). The load capacity price would not be significant in an era of price taking fixed load, but the understated capacity price could be a negative in an era of large loads such as data centers being sited.

These examples suggest to FTI a need to consider some type of combined capacity zone clearing in such an auction model.

The delineation of combined zones in the Auction model would be straightforward in the examples with only 2 zones but would be more complex if there were many zones. However, we need not nest all zones in an auction model. We could nest NYC within GHIJ, and GHIJ within NYCA, along with all of the other zones. It appears to FTI that more complex types of nesting for upstate with many combinations of zones and price relationships between the zones could result in some solution complexity. Nevertheless, we think it would be workable to clear Zone A, then Zone B and then a combined Zone A and B with all offers included, whether or not the offers cleared in the zonal solutions. Prices from the combined zone would cascade to the individual zones if they were higher.

IV. Other

These examples assume that all zones have the same reference price. This would result in very low prices for NYC capacity if the CONE for NYC was based on the CONE for upstate. Conversely, the design would result in very high prices for upstate if upstate used the CONE for NYC. Hence, it seems to FTI that the NYISO would still need to set different reference prices for the zones in this type of auction model.

Potential for Market Power Issues with a Kinked Demand Curve

Scott Harvey, Tim Schittekatte and Victoria Lorvig

August 19, 2025

Introduction

An underlying issue in discussions is the cost used to anchor the demand curve. This is that, with the NYISO capacity market demand curve design, the clearing price will be different for the same amount of excess capacity depending on the cost used to anchor the demand curve. In particular, a higher demand curve anchor cost will result in higher prices when there is substantial excess supply as well as when there is tight supply.

Rate payer concerns with capacity prices and costs are not fully articulated and there appear to be diverse views across stakeholders concerning rate payer costs. One possible driver for a demand curve anchor based on estimated going forward costs, rather than estimated Net CONE of a Gas Turbine (GT), might be a goal of paying low capacity prices when there is a shortage of capacity. In our view, Potomac's analysis has shown that designs of this type would not be workable from the standpoint of either rate payer costs or reliability.[59]

Another possible rate payer concern might be a scenario with higher prices for capacity and higher capacity costs attributable to the GT Net CONE demand curve anchor, relative to a demand curve anchor based on going forward costs when there is a high level of excess capacity. The capacity price level when there is significant excess capacity would be less of a rate payer concern if it was clear that the capacity price was reasonably related to the reliability value of the capacity.

A lower demand curve anchor, such as an anchor based on going forward costs, reduces capacity prices and payments when there is substantial excess capacity, relative to a Net CONE based demand curve anchor. However, as noted above, a going forward costs demand curve anchor also reduces capacity price when there is an emerging capacity shortfall and high capacity prices are needed to retain capacity needed to meet load.

Concerns with high capacity prices and capacity costs when there is a capacity surplus could potentially be addressed by a kinked demand curve which sets lower prices than the current demand curve when there is a large surplus of capacity but sets prices that rise rapidly as the supply of capacity declines and approaches the target. Such a kinked demand curve would consist of three segments as shown in Figure 1. Starting on the far-right, the lowest demand curve segment would have a flatter slope than a 'standard demand curve' anchored by net CONE, because it is anchored by the net going forward costs of a GT. This segment would extend to a specified kink quantity, shown as Q_k in Figure 1. The next segment would begin at the kink quantity and slope up to the reference price based on the Net CONE of a GT.[60] This segment would be steeper than a demand curve based on Net CONE of a GT and having the same zero crossing point.[61] A third segment would follow a demand curve based on the Net CONE of a GT above the reference price and up to the maximum price of the demand curve based on the Net CONE of a GT.

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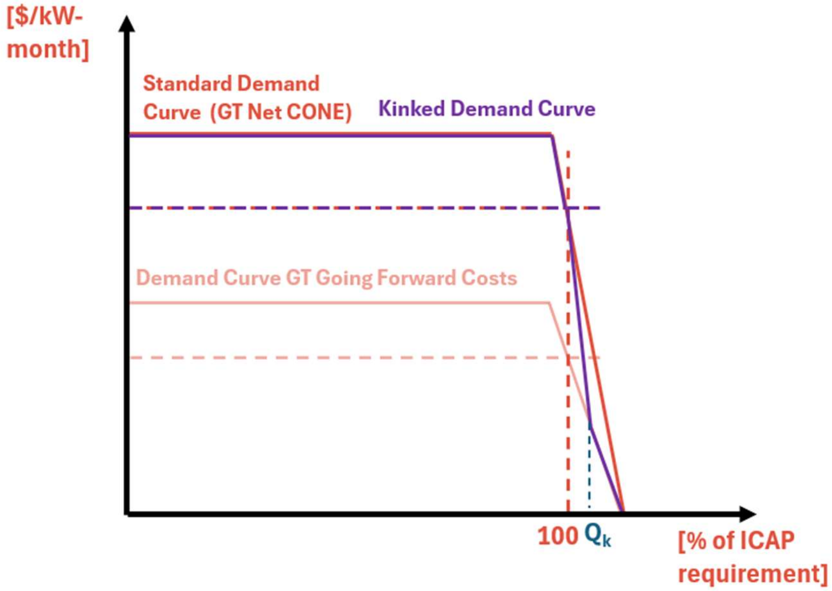
[59] See MMU Analysis of Capacity Market Structure, Joe Coscia, Potomac Economics, May 22, 2025.

[60] The reference price is the capacity price when the cleared capacity supply equals the ICAP requirement.

[61] The zero-crossing point is the volume of cleared capacity supply for which the capacity price is zero.

Figure 1: Standard GT Net CONE, GT Going Forward Cost and Kinked demand curves



The kinked demand curve pictured in Figure 1 is not the only possible demand curve shape. The slope of the lower kink is set equal to the slope of a demand curve based on assumed going forward costs. This choice was made in the context of the discussion with stakeholders favoring a demand curve anchored by the going forward costs of a GT, hence the slope of the lower segment of the kinked demand curve. On the other hand, Potomac's analysis of such a demand curve anchor showed that it would lead to adverse impacts as capacity shortage approached, hence the kink. Such a demand curve would set low capacity prices for large levels of surplus, but prices would rise rapidly as the surplus declined above the lower kink. This type of kinked demand curve could avoid the outcome in the Potomac simulations based on a going forward cost demand curve which led to high cost back up generation being built at the same time lower cost existing capacity is shutting down.[62] Under a kinked demand curve design, high capacity prices would be a result of the state failing to incent the construction of enough subsidized capacity to maintain a capacity surplus and the high prices set by the kinked demand curve would help keep needed existing capacity in operation. In principle, the location of the kink with respect to quantity could be set at any level between the zero-crossing point and the ICAP requirement).

One concern with such a kinked demand curve is whether it would be more susceptible to the exercise of market power relative to the standard demand curves anchored by the Net CONE or going forward costs of a GT. The potential for the exercise of market power arises from the somewhat steeper slope of the demand curve at prices between the kinks. Conversely, the kinked demand curve has a flatter slope for prices below the kink compared to the standard demand curve. In this note, we analyze the potential for the exercise of market power in more detail.

We show in Section III that a kinked demand curve can increase the incentive of suppliers with significant market shares to economically withhold capacity. However, the impact on incentives is not material for suppliers with small market shares, and prices and consumer costs may still be lower with the kinked demand

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[62] See MMU Analysis of Capacity Market Structure, Joe Coscia, Potomac Economics, May 22, 2025.

curve because the demand curve is lower than the standard demand curve and produces a lower price for the same quantity. Moreover, the increased potential for the exercise of market power is limited to outcomes on the upper portion of the demand curve in which there is a small surplus. With large capacity surpluses the kinked demand curve produces lower prices and often much lower prices than the standard demand curve unless market shares are 10% or more.

We then show in Section IV that the cases in which a strategic supplier would have the incentive to economically withhold enough capacity to increase prices and consumer costs almost always fall in the range in which the supplier would be determined to be pivotal and subject to mitigation. If our understanding of the market power mitigation design is correct, it does not appear in most cases that the kinked demand curve would increase the potential for the exercise of market power and higher prices, but would instead result in lower prices, particularly if there is a large surplus of capacity.

A final topic discussed in Section V is that the results regarding prices and consumer costs are all short-run outcomes, with supply held constant. Because the type of kinked demand curve we discuss will always result in lower prices than a standard demand curve with the same anchor and zero crossing point if there is no exercise of market power, the kinked demand curve has the potential to speed the exit of existing capacity. This exit would raise capacity prices and consumer costs in the long run. Hence, there is a potential inconsistency in the goal of lowering consumer costs through lower prices for existing capacity in the short run, versus the long run. It is important to recognize that both the standard demand curve and the kinked demand curve have the property that total consumer payments decline with higher levels of capacity. Speeding the exit of capacity through lower prices when there is a large surplus of capacity, can result in higher capacity prices and consumer costs in the not very long run.

The same inconsistency exists with a demand curve anchor based on GT going forward costs. Any anchor that results in prices below the going forward costs of a material amount of existing capacity when there is significant excess capacity could result in low prices in the short run and higher prices in the long run. Hence, realizing rate payer benefits of low capacity market costs from such a design would require enough new capacity being built to replace exiting existing capacity. If that is the case, the kinked demand curve will lower capacity market costs. If there is not enough new supply entering, the kinked demand curve will produce a rising capacity price and retain more existing capacity.

In Section II we illustrate the operation of a kinked capacity market demand curve under perfect competition with varying levels of excess capacity in the market. In Section III we analyze market power incentives for a strategic capacity supplier with a range of market shares across varying levels of overall capacity available in the market, without any market power mitigation. In Section IV we extend the examples in Section III to account for the NYISO's capacity market power mitigation design. Finally, in Section V we provide preliminary conclusions.

Analysis of kinked demand curve under perfect competition

This section illustrates the operation of a kinked demand curve design for a specific kink design, across a variety of supply-demand balances. We illustrate the operation of a kinked demand curve design for supply that is 102% of target, 105%, 108%, 110% and 112%. We assume that all supply is offered at a price of $0.

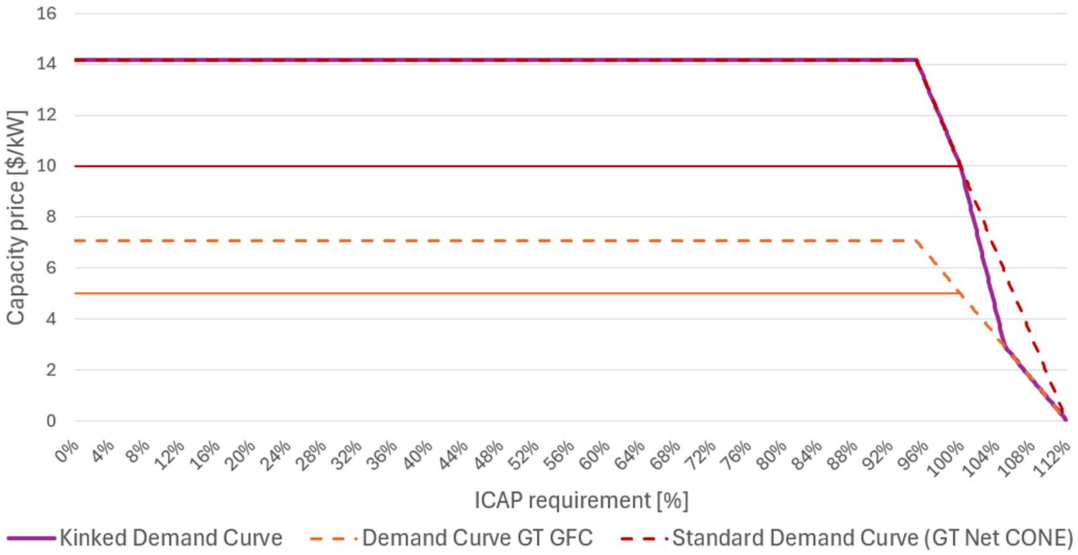
In the numerical examples we assume an ICAP of 5000 MW and the parameters described in Table 2 for the different demand curves.

Table 2: Parameters of alternative demand curves

	Standard Demand Curve (GT Net CONE)	**Demand curve GT going forward cost (GFC)**	**Kinked Demand curve**
Reference price [$/kW]	10	5	10
Zero-crossing point [%]	112%	112%	112%
Price cap [%]	Reached at ≤ 95% of ICAP requirement	Reached at ≤ 95% of ICAP requirement	Reached at ≤ 95% of ICAP requirement
Upper kink	none	none	100%
Lower kink	none	none	105%

The resulting demand curves are shown below in Figure 3.

Figure 3: Three demand curves and their reference prices described in Table 2 with an ICAP requirement of 5000 MW



In this section we focus on comparing market outcomes for the standard demand curve anchored by GT Net CONE (the current demand curve) and a kinked demand curve. Assuming perfect competition and price-taking offers, the kinked demand curve will result in lower prices for all levels of capacity supply up to the target capacity. With the upper kink being set at 100% of the ICAP requirement, the capacity prices will be the same above the reference price (capacity less than target), while the capacity price will be lower for the kinked demand curve if more than 100% of the ICAP requirement is cleared (surplus). The outcome of the capacity market clearing for 105% of the ICAP requirement being cleared (blue line) is shown in Figure 4 below.

Figure 4: Capacity market outcome with supply equal to 105% of ICAP requirement and perfect competition

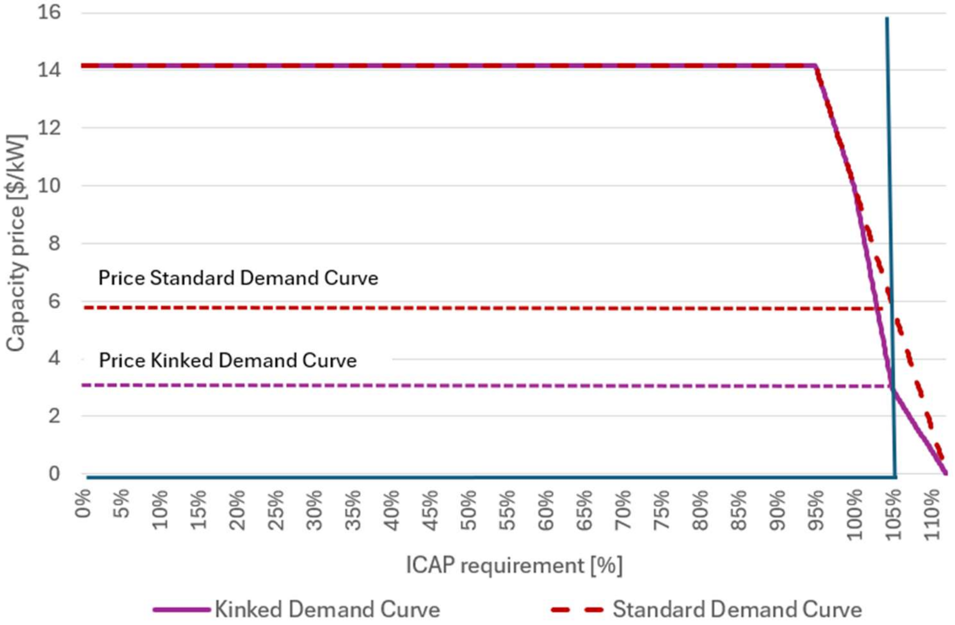


Figure 4 shows that the difference between the price determined by the kinked demand curve and the standard demand curve is greatest at the kink ($5.83/kW for the standard demand curve and $2.92/kW for the kinked demand curve). This difference in prices results in a total consumer cost of $30.6 million with the standard demand curve, compared to a consumer cost of $15.3 million with a kinked demand curve.

Table 5 shows prices and consumer payments for standard and kinked demand curves for supply levels ranging from 102% to 112% of target when there are no strategic suppliers, that is no suppliers have a large enough market share to profit from economically withholding supply. One can see that the kinked demand curve produces lower prices and consumer costs over the entire range of ICAP supply levels.

Table 5: Price and Cost outcomes with alternative ICAP supply levels - perfect competition

	102% of ICAP		**105% of ICAP**		**108% of ICAP**		**110% of ICAP**		**112% of ICAP**	
Demand curve	**Standard**	**Kinked**	**Standard**	**Kinked**	**Standard**	**Kinked**	**Standard**	**Kinked**	**Standard**	**Kinked**
Capacity price [$/kW]	8.33	7.17	5.83	2.92	3.33	1.67	1.67	0.83	0	0
Consumers payments [M$]	42.5	36.6	30.6	15.3	18.0	9.0	9.2	4.6	0	0

Outcomes under imperfect competition – No market power mitigation

Conceptual Framework

In this section we shift to analyzing the impact of a kinked demand curve on capacity prices and consumer capacity payments when there is one strategic capacity supplier that has the potential ability to exercise market power. The remaining supply is assumed to be offered in the market as price taking, thereafter referred to as "fringe" supply. Physical withholding is not allowed, so suppliers seeking to exercise market power would economically withhold supply by offering it at the profit maximizing price.

The capacity market model used in the examples is simplified in some respects to provide a good starting point for understanding the issues. First, the examples are more relevant to Zone J than to Zone GHIJ or NYCA because we do not consider nested zones. This type of model could be applied in a second stage, but it would introduce a number of variations that would need to be considered. Second, the examples consider a single strategic supplier with a competitive fringe. A market model with multiple strategic suppliers would be an oligopoly model in which there a variety of possible outcomes. There is an extensive and complex economic literature on solving these models. Third, we assume the cost of capacity in the spot auction is zero, both for the strategic supplier and fringe supply. This assumption is valid in the very short run, but not in the long run as we will discuss in Section V below.

In the examples we assume the strategic supplier's short-run marginal cost is zero and that the strategic supplier will set an offer price that clears the quantity that maximizes its short-term profits, i.e., the quantity at which point its marginal revenue for offering one more unit is zero.[63] There are more complicated models in which the strategic supplier offers are based on its long-run cost of capacity, taking account of impacts of the current clearing price on expectations for future prices. We will focus on this simplified model for this initial discussion.

Marginal revenue (MR) is calculated as:

$$[1] \qquad MR(Q) = P(Q) + \partial P/\partial Q * Q$$

with P being the capacity price, Q the profit-maximizing quantity cleared by the strategic supplier and $\partial P/\partial Q$ the derivative of price with respect to quantity. We note that the steeper the slope of the demand curve ($\partial P/\partial Q$) and the larger the cleared quantity of the strategic supplier (Q), the more rapid marginal revenue declines, and it becomes more profitable to economically withhold supply.

We start by providing an example for a supplier controlling 10% market share when the total market capacity supply equals 102% of the ICAP requirement. We then work through the example for a supplier with a 3% market share for the same total capacity supply. After working through these detailed examples, we analyze the five supply levels that were analyzed in Section II. In addition, we analyze capacity market outcomes for strategic suppliers controlling 3%, 4%, 6%, 10% and 20% of the market supply.

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[63] In case of the kinked demand curve, in some cases there can be multiple cleared quantities at which the marginal revenue is zero. In that case, the profit maximising quantity cleared is the quantity for which the marginal revenue is zero and the absolute revenue is highest.

Illustrative Detailed Examples

We explain the potential for the exercise of market power with two detailed examples. The first is a case with a small supply surplus relative to the requirement and a strategic supplier with a large market share. The second example again assumes that there is a small capacity surplus but the strategic supplier has a much smaller market share than in the first example.

Supply equal to 102% of requirement, strategic supplier has a 10% market share

We start with an example for a supplier with a 10% market share and the total capacity supply equals 102% of the ICAP requirement. Hence, the total ICAP supply is 5100 MW of which 510 MW is owned by the strategic supplier and 4590 MW by the fringe. To understand the profit maximizing offer price of the strategic supplier, we calculate its additional revenue for one additional MW cleared on top of the 4590 MW fringe supply (i.e., marginal revenue). Figure 6 shows the marginal revenue of the strategic supplier for the range of quantity cleared by the strategic supplier for the two considered demand curves (standard and kinked) up to the quantity for which the marginal revenue equals zero.

For both demand curves, marginal revenue is flat and equal to the price cap up to 160 MW being cleared by the strategic supplier. The total cleared supply would be 95% of the ICAP requirement with this amount of supply cleared by the strategic supplier. The strategic supplier would need to reduce its offer price in order to clear capacity above this level. Marginal revenue decreases as the demand curve slopes down with more quantity cleared at lower prices (the slope of the demand curve is - $0.0167/kW). If 410 MW of the supply of the strategic supplier is cleared, the total cleared supply equals 5000 MW. Figure 6 shows that up to 410 MW the marginal revenue from clearing incremental capacity is positive for both demand curves.

Under the kinked demand curve, clearing one additional megawatt of capacity would set the price determined by the steeper segment of the demand curve (having a slope of - $0.0283/kW). Due to the steepness of that demand curve segment and the fact that 410 MW of the strategic supplier's total capacity of 510 MW would clear, the slope of the marginal revenue becomes steeper than for the standard demand curve and the marginal revenue becomes negative for output levels in excess of the upper kink quantity. The marginal revenue for the strategic supplier at 410 MW cleared on the kinked demand curve is -$1,617/MW.[64] Thus, the revenue of the strategic supplier would decrease by $1,617 if it reduced its offer price enough to increase its cleared quantity by 1 megawatt. This negative marginal revenue corresponds to a reduction in profits in this price/quantity range. The profits of the strategic supplier would be $4,100,000 with 410 MW cleared at a price of $10.0/kW and would be $4,098,355 with 411 MW cleared at a price of $9.97/kW.[65] Hence the optimal cleared quantity for the strategic supplier is 410 MW.

For the standard demand curve, the demand curve has a constant slope (- $0.0167/kW) for market quantities in excess of 95% of the ICAP requirement up to the zero-crossing point. The marginal revenue curve equals zero

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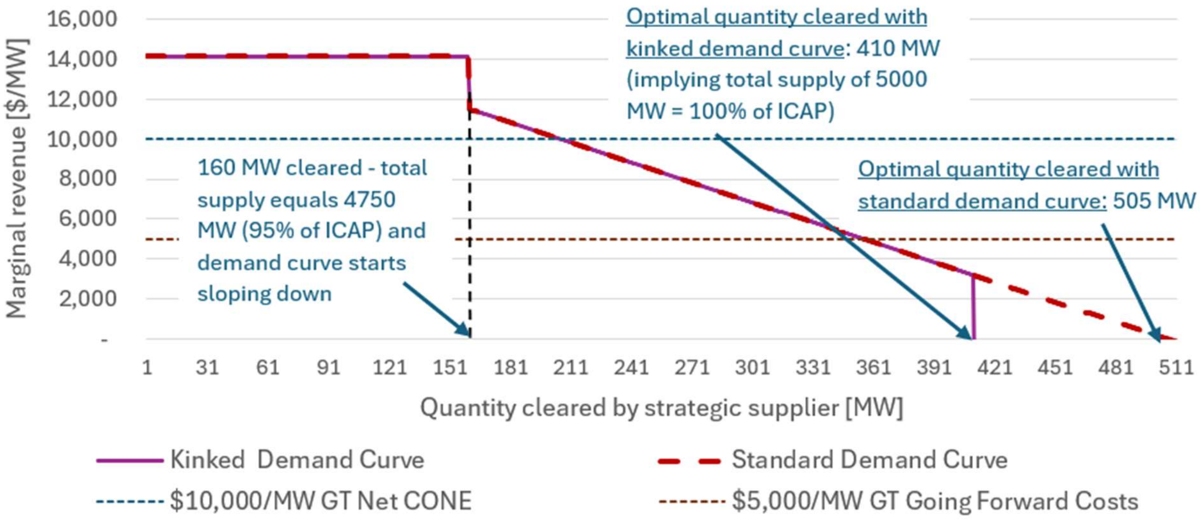
[64] The marginal revenue for the strategic supplier clearing 410 MW can be calculated as: MR = $\$10.00*10^3$/MW - $\$0.0283*10^3$ /MW*410 MW = -$1,617/MW.

[65] There is a minor difference between the marginal revenue and the incremental revenue calculated for 1 MW.

for 505 MW cleared at a price of \$8.42/kW.[66] The profits of the strategic supplier would be \$4,250,417 with 505 MW cleared and would be \$4,250,400 with 506 MW cleared. Hence the optimal cleared quantity for the strategic supplier is 505 MW at a price of \$8.42/kW. The cleared capacity (505 MW) of the strategic supplier is only 5 MW short of the quantity cleared under perfect competition (510 MW).

Figure 6: Marginal revenue of the strategic supplier for different cleared quantities



For the standard demand curve, the total supply in the capacity market that would clear is 5095 MW (4590 MW + 505 MW). For the kinked demand curve, the strategic supplier would clear 410 MW and the total market would clear 5000 MW (4590MW + 410 MW). The market clearing results are illustrated in Figure 7. Due to the economic withholding of capacity by the strategic supplier the capacity price is higher for the kinked demand curve (\$10.0/kW) than for the standard demand curve (\$8.42/kW). These results are summarised in Table 8.

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[66] The marginal revenue for the strategic supplier clearing 505 MW can be calculated as: MR = \$8.42*10^3 /MW - \$0.0167 *10^3 /MW*505 MW = \$0/MW.

Figure 7: Capacity market outcomes with capacity supply 102% of ICAP requirement and 10% market share of the strategic supplier

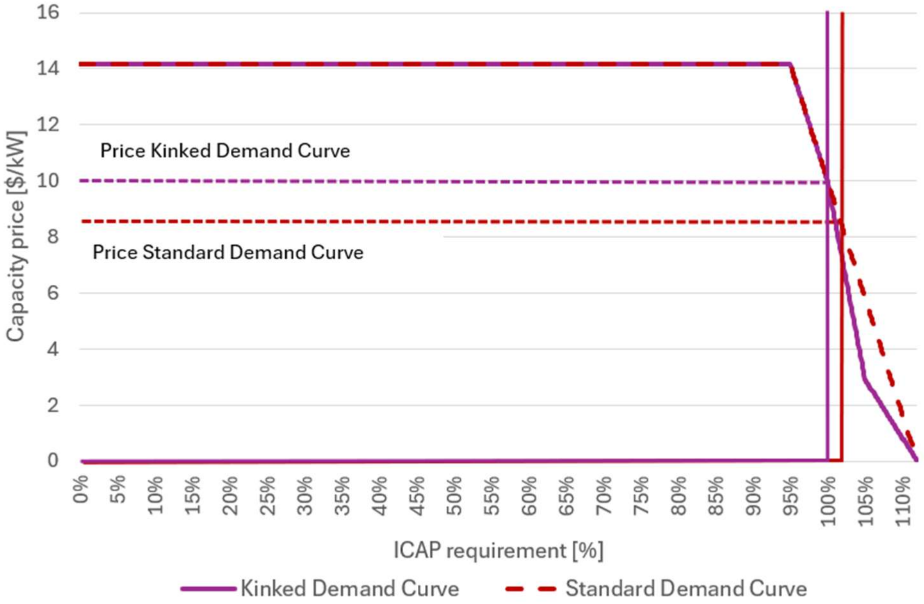


Table 8: Outcomes when ICAP Supply is 102% of the requirement - strategic supplier 10% market share

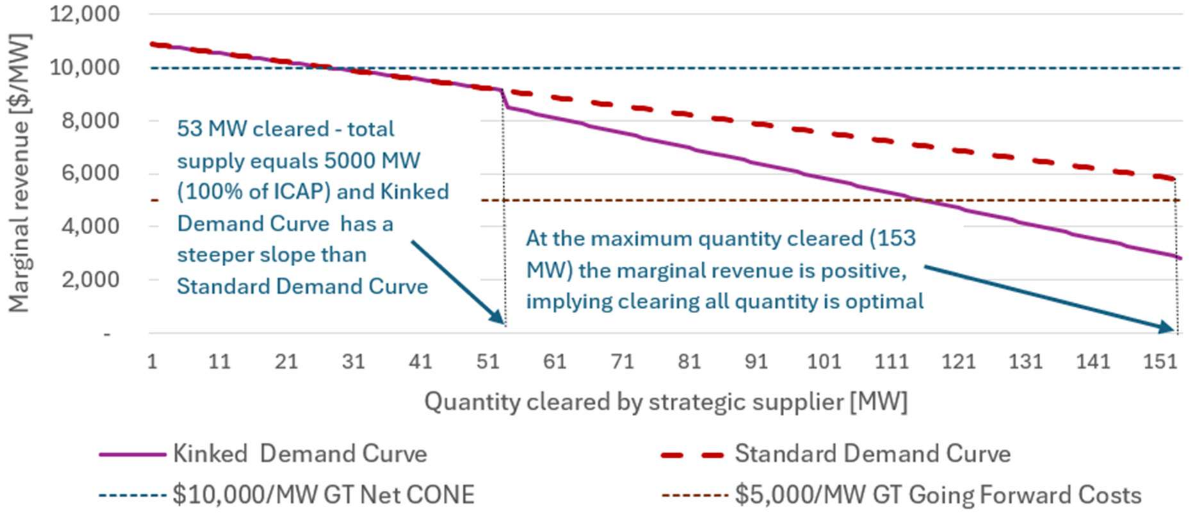
	Standard Demand curve	Kinked Demand curve
Cleared supply [MW]	5095	5000
Capacity price [$/kW]	8.42	10.00
Cost to consumers [M$]	42.90	50.00

An important element of this example is that the strategic supplier in this example with a 10% market share would meet the definition of a pivotal supplier under NYISO Market Services Tariff (MST) attachment H and its offers would be subject to mitigation. We will consider this further in Section IV.

Supply equal to 102% of requirement strategic supplier has a 3% market share

In this example we assume the same total capacity supply of 102% of the ICAP requirement but reduce the market share of the strategic supplier to 3%. Hence, the total ICAP supply is 5100 MW of which 153 MW is owned by the strategic supplier and 4947 MW by the fringe. We calculate the marginal revenue of the strategic supplier for different cleared quantities in addition to the 4947 MW fringe supply. Figure 9 shows the marginal revenue of the strategic supplier for the offer prices and cleared quantities of the strategic supplier for the two demand curves up to the maximum quantity the strategic supplier can supply.

Figure 9: Marginal revenue of the strategic supplier for different cleared quantities



The marginal revenue is identical for both demand curves for quantities up to 53 MW cleared by the strategic supplier. This is because the demand curves are identical up to that point, i.e., they both have a slope of -$0.0167/kW. At 53 MW of supply cleared by the strategic supplier, the total cleared supply equals 100% of the ICAP requirement. For cleared capacity supply above 100% of the ICAP requirement, marginal revenues for the standard demand curve continue decreasing with the same slope as above that quantity. The slope of the marginal revenues with the kinked demand curve becomes steeper because the kinked demand curve is steeper for quantities above 100% of the ICAP requirement (having a slope of - $0.0283/kW) and the strategic supplier would only clear 53 MW at the upper kink, so the change in revenues from reducing the offer price in order to clear additional capacity is low relative to the clearing price paid for incremental supply.

At 153 MW cleared by the strategic supplier, which is the total supply of the strategic supplier, marginal revenue is still positive for both demand curves. At that cleared quantity, clearing a marginal megawatt of capacity would result in total revenues of $1,096,500 with an increase of $2,832/MW from the sale of an incremental megawatt of capacity at the margin for the kinked demand curve and would result in total revenues of $1,275,000 with an increase of $5,783/MW at the margin for the standard demand curve.[67]

These results for marginal revenue imply that the optimal cleared quantity of the strategic supplier is to clear all its capacity, which leads to the same result as under perfect competition (see Table 5). This example illustrates the fact that with high capacity prices, due to limited capacity supply, marginal revenues are high, so a supplier with a market share of 3% or less would find it very profitable to clear additional supply at a slightly lower price.

The resulting capacity prices set by the kinked and standard demand curve are $7.17/kW and $8.33/kW, respectively, as shown in Figure 10. As the total quantities cleared for both demand curves is the same,

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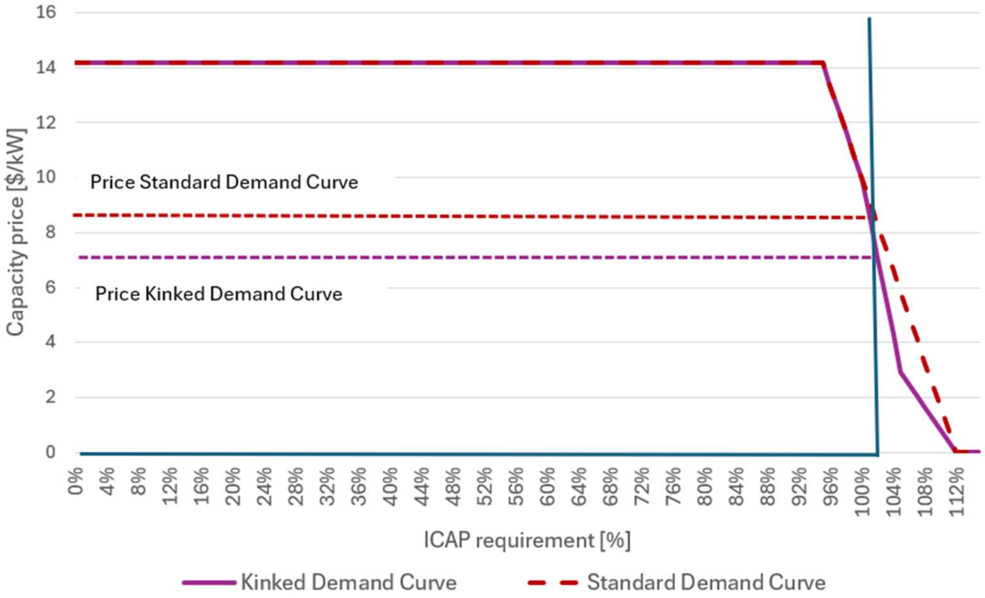
[67] For the kinked demand curve the revenue at 153 MW cleared equals 153 MW*$7.17*$10^3$/MW= $1,096,500 and the marginal revenue equals $7.17*$10^3$ /MW -$0.0283 *$10^3$ /MW*153 MW = $2,832/MW. For the standard demand curve the revenue at 153 MW cleared equals 153 MW*$8.33*$10^3$/MW= $ 1,275,000 and the marginal revenue equals $8.33*$10^3$/MW - $0.0167*$10^3$/MW*153 MW = $5,783/MW.

consumer costs are lower under the kinked demand curve than under the standard demand curve: $36.6 million vs $42.5 million.

Figure 10: Capacity market outcome with capacity supply 102% of ICAP requirement and 3% market share of the strategic supplier



Summary results for varying capacity supply levels and market shares

In the cases that follow we apply the same methodologies for other combinations of assumed ICAP supply (102%, 105%, 108%, 110% and 112% of requirements) and market shares of the strategic supplier (3%, 4%, 6%, 10% and 20% of the market supply). The general pattern is that when the market share of the strategic supplier is large compared to the degree of capacity surplus relative to the requirement, there is generally more economic withholding and higher prices with the kinked demand curve than with the standard demand curve. Conversely, if the market share of the strategic supplier is small relative to the degree of capacity surplus, prices tend to be lower, often much lower, with the kinked demand curve than with the standard demand curve.

Capacity Supply 102% of ICAP Requirement

Figure 11 shows the consumer payments with tight supply – total capacity supply equal to only 102% of the ICAP requirement, for both the standard demand curve and a kinked demand curve for various market shares of the strategic supplier. Table 11 shows the capacity prices and cleared quantities for both the standard demand curve and a kinked demand curve for various market shares of the strategic supplier. For strategic supplier market shares up to 4%, the optimal strategy of the strategic supplier is to offer all its capacity at prices that clear for both demand curves (see the example in 0).[68] Thus the cleared capacity is the same as the

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[68] In other words, the marginal revenue never falls to zero within the range of possible quantities cleared by the strategic supplier.

outcome under perfect competition (0% market share). However, consumer costs are lower with the kinked demand curve because the capacity price is lower for the same amount of cleared capacity.

At 6% market share, the outcome under the standard demand curve remains the same as under perfect competition, but some capacity is economically withheld by the strategic supplier under the kinked demand curve. However, because the kinked demand curve is lower than the standard demand curve, the withholding incented by the kinked demand curve is not large enough to raise the price of capacity above the price determined by the standard demand curve (see Table 12). Hence, consumer payments are still lower with the kinked demand curve than with the standard demand curve.

At 10% market share (as shown in detail in the previous section III.1), there is only a small amount of capacity economically withheld by the strategic supplier under the standard demand curve, while more capacity would be economically withheld under the kinked demand curve. In this case, there is a large price increase under the kinked demand curve, which causes consumer payments to be higher under the kinked demand curve, even though less capacity would be cleared.

Finally, if the strategic supplier has a 20% market share, the same quantity is economically withheld by the strategic supplier with either demand curve by offering supply at the profit maximizing clearing price. This leads to a total supply of 4839 MW which is below the capacity requirement. In this range of cleared capacity, there is no difference between the demand curves, so the prices and quantities are the same.

Figure 11: Consumer payments with capacity supply equal to 102% of ICAP requirement

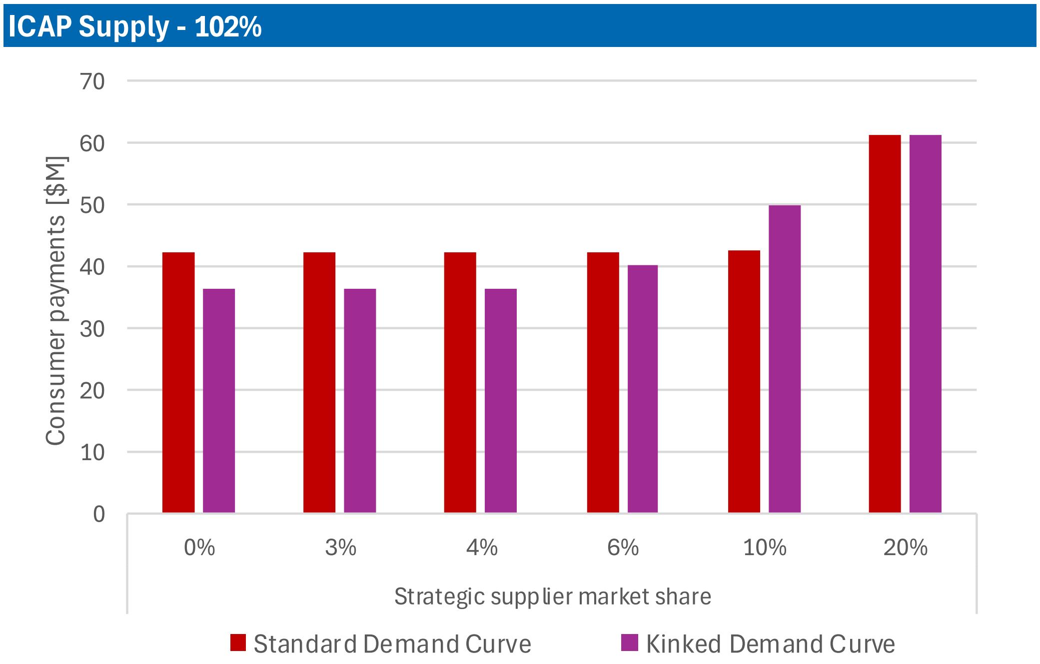

Table 12: Clearing prices and quantities with capacity supply equal to 102% of ICAP requirement

Clearing price [$/kW]

	Strategic supplier market share					
	0%	3%	4%	6%	10%	20%
Standard demand curve	8.3	8.3	8.3	8.3	8.4	12.7
Kinked demand curve	7.2	7.2	7.2	7.9	10.0	12.7

Total Cleared quantity [MW] ■ ■ ■ ■ ■ ■

	Strategic supplier market share					
	0%	3%	4%	6%	10%	20%
Standard demand curve	5100	5100	5100	5100	5095	4840
Kinked demand curve	5100	5100	5100	5073	5000	4840

Capacity Supply 105% of ICAP Requirement

This case shows a similar pattern of lower prices and consumer costs with the kinked demand curve for low market shares of the strategic supplier but higher prices and consumer costs for large market shares (see Figure 13). However, consumer payments are much lower for low strategic supplier market shares than in the prior case, because the increase in total supply implies larger fringe supply relative to the ICAP requirement. As shown in Table 14 below, compared to a case of capacity market supply of only 102% of the ICAP requirement, there is more economic withholding of capacity by the strategic supplier at low market shares, with less supply cleared under the kinked demand curve with market shares of 4% and 6%, while there is no economic withholding with a 4% market share with the standard demand curve.[69]

At a 4% market share there is some economic withholding by the strategic supplier under the kinked demand curve, while the outcome under the standard demand curve is the same as under perfect competition where the strategic supplier is incented to clear all available capacity.[70] However, the prices determined by the kinked demand curve are so much lower than the prices determined by the standard demand curve that the clearing prices is almost 25% lower based on the kinked supply curve and consumer cost is also much lower with the kinked demand curve.

At 6% market share of the strategic supplier, consumer payments under both demand curves are about the same, i.e., the impact of economic withholding of capacity with the kinked demand curve leads to the same consumer payments as the competitive outcome with a standard demand curve because the price is slightly higher with the kinked demand curve than with the standard demand curve.

Above 6% of market share of the strategic supplier, there is less capacity withheld under the standard demand curve than with the kinked demand curve and the price is materially higher with the kinked demand curve. The

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[69] The marginal revenue never reaches zero within the range of possible quantities cleared by the strategic supplier. This threshold is 7.7% of market share for standard demand curve.

[70] Up to a market share of 7.7%, at which level there is economic withholding under the standard demand curve, too.

price increase with the kinked demand curve is large enough to make the consumer payments higher under the kinked demand curve for a 10% market share of the strategic supplier.

Finally, when assuming the strategic supplier has a 20% market share, the same amount of capacity is economically withheld under both demand curves, leading to a total cleared supply of 4900 MW which is below the target capacity.

Figure 13: Consumer payments with capacity supply equal to 105% of ICAP requirement

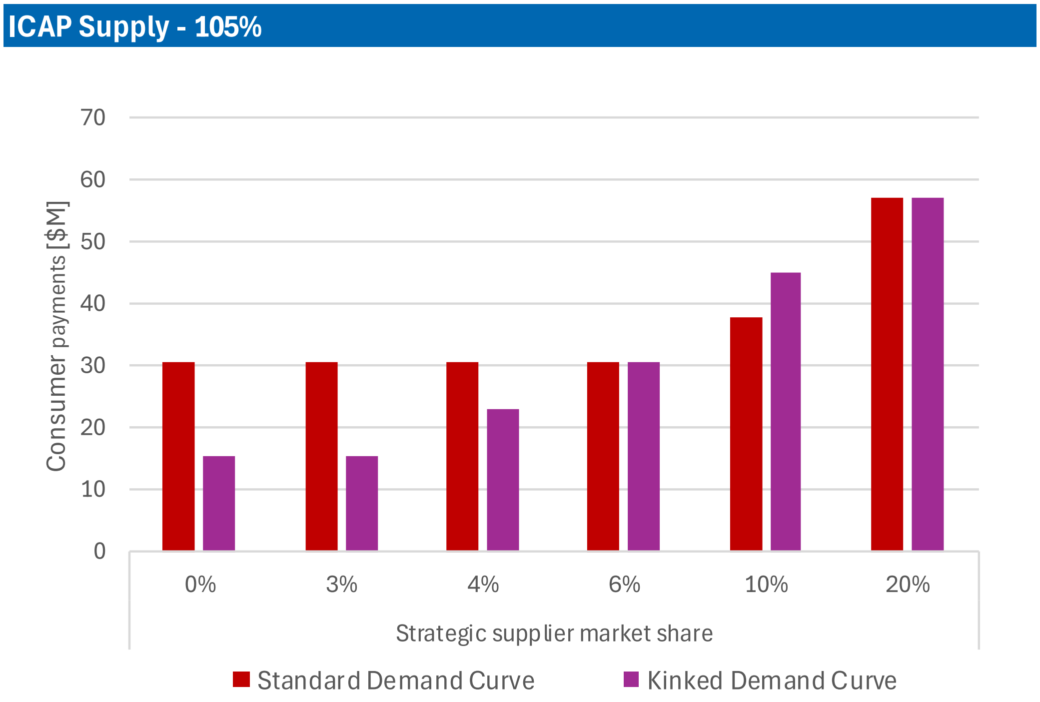

Table 14: Clearing prices and quantities with capacity supply equal to 105% of ICAP requirement

ICAP Supply - 105%

Clearing price [$/kW]

	Strategic supplier market share					
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	5.8	5.8	5.8	5.8	7.3	11.7
Kinked demand curve	2.9	2.9	4.4	5.9	8.9	11.7

Total Cleared quantity [MW]

	Strategic supplier market share					
	0%	**3%**	**4%**	**6%**	**10%**	**20%**

Standard demand curve	5250	5250	5250	5250	5162	4900
Kinked demand curve	5250	5250	5196	5143	5038	4900

Capacity Supply 108% of ICAP Requirement

With an 8% level of excess supply in the capacity market there is even less difference between the amount of economic withholding depending on the demand curve slope, while the kinked demand curve results in much lower prices for the same amount of cleared capacity. This reduced incentive to economically withhold capacity is due to the increase in total available capacity, which causes the fringe supply alone to exceed the ICAP requirement unless the strategic supplier market share exceeds 8%. Moreover, none of the supply of a strategic supplier with 3% or less market share is needed to clear supply at the lower demand curve kink (105% of ICAP requirement). While there is some economic withholding by a strategic supplier with more than 3% market share, the amount it is profitable to withhold is relatively small because the supplier would be selling very little capacity if they economically withheld a large enough for the market to clear on the steep portion of the kinked demand curve.[71] Similar to the cases with less supply, the optimal strategy for strategic suppliers with less than 4% market share is to clear all their capacity under both demand curves.

The level of economic withholding is the same for both demand curves until the strategic supplier has about 10% market share, above which there is more capacity withheld under the kinked demand curve design than under the standard demand curve. This creates a large enough price increase with the kinked demand curve to make the consumer payments larger for the kinked demand curve for a strategic supplier with a 10% market share.

Finally, if the strategic supplier has a 20% market share, the same quantity is economically withheld under both demand curves leading to the same total supply of 4959 MW which is below the capacity requirement.

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[71] Up to and including 6% market share, the cleared quantity under both demand curves is below 5250 MW (see Table 16) and for the kinked demand curve prices are set by the flatter segment of the demand curve.

Figure 15: Consumer payments with capacity supply equal to 108% of ICAP requirement

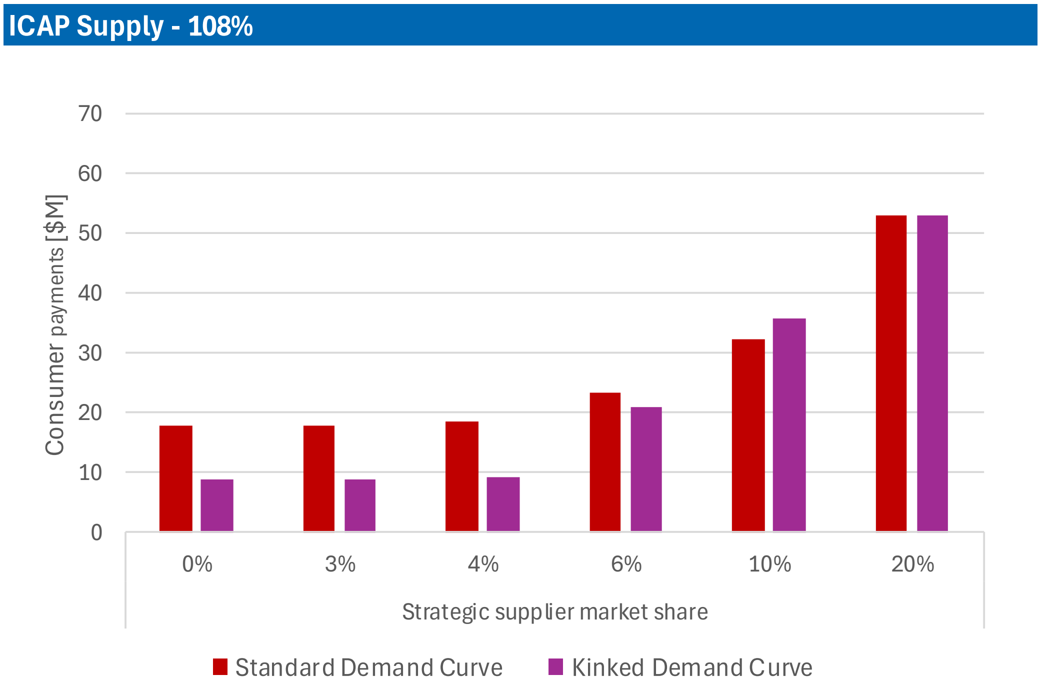

Table 16: Clearing prices and quantities with capacity supply equal to 108% of ICAP requirement

Clearing price [$/kW]

	Strategic supplier market share					
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	3.3	3.3	3.5	4.4	6.2	10.7
Kinked demand curve	1.7	1.7	1.7	3.9	7.0	10.7

Total Cleared quantity [MW]

	Strategic supplier market share					
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	5400	5400	5392	5337	5230	4960
Kinked demand curve	5400	5400	5392	5337	5106	4960

Capacity Supply 110% of ICAP Requirement

With a 10% level of excess supply in the capacity market, the difference in the amount of economic withholding between the two demand curves decreases further. For supply equal of 110% of the ICAP requirement, the pattern of consumer payments being significantly lower with the kinked demand curve for low market shares of the strategic supplier (up a market share between 6% and 10%) continues. Table 18 shows that it becomes economic to withhold under both demand curves at relatively low market shares of the strategic supplier. However, because the fringe supply is so large relative to the ICAP requirement, the clearing price is below the kink in the kinked demand curve for strategic supplier market shares up to and at 6%, and the same quantities are withheld for both demand curves. The impact on capacity prices of the economic withholding is lower under the kinked demand curve, because the supply clears on the flatter segment of the demand curve (> 105% of the ICAP requirement). Thus with the standard demand curve and a strategic supplier with 4% market share, the clearing price is $2.7/kW month compared to the competitive price of $1.7/kW, while with the kinked demand curve the price is $1.3/kW month compared to the competitive price of $0.8/kW. Figure 17 shows that consumer costs are also materially lower with the kinked demand curve. This is the case for market shares up to and at 6% of the strategic supplier.

At 10% market share, there is a limited amount of capacity economically withheld by the strategic supplier under the standard demand curve, with supply clearing at a price below the kink, while more supply is withheld with the kinked demand curve and supply clears above the kink on the steeper segment of the demand curve. This additional economic withholding results in a large enough price increase to make consumer payments slightly larger with the kinked demand curve than with the standard demand curve.

Finally, if the strategic supplier has a 20% market share, the same quantity is economically withheld for both demand curves leading to the same total supply of 5000 MW which is equal to the target capacity.

Figure 17: Consumer payments with capacity supply equal to 110% of ICAP requirement

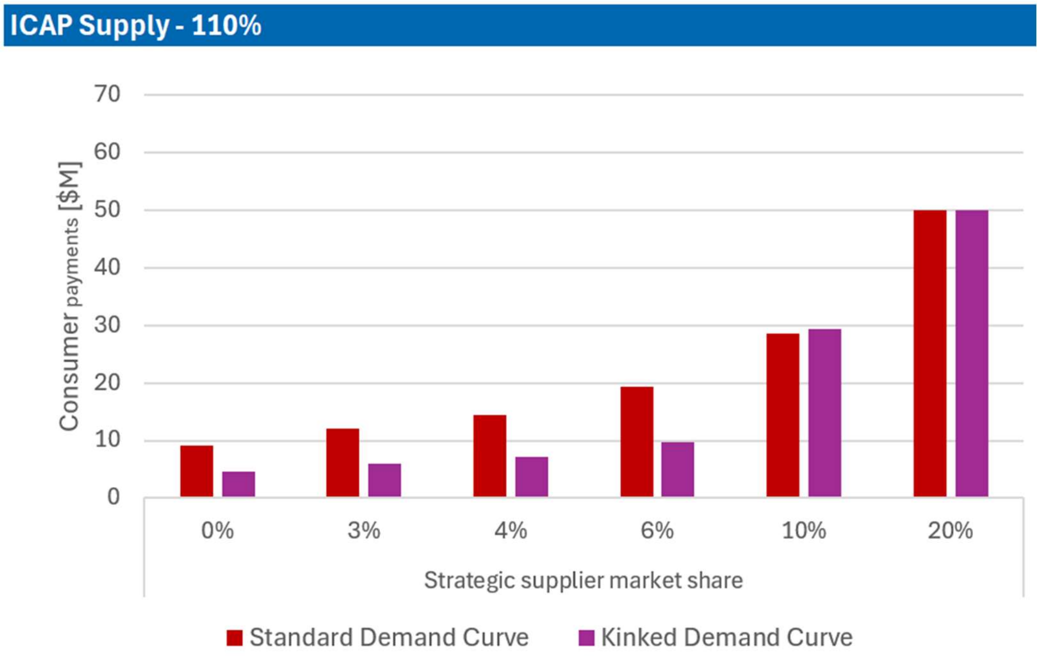

Table 18: Clearing Prices and quantities with capacity supply equal to 110% of ICAP requirement

Clearing price [$/kW]

				Strategic supplier market share		
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	1.7	2.2	2.7	3.6	5.4	10.0
Kinked demand curve	0.8	1.1	1.3	1.8	5.7	10.0

Total Cleared quantity [MW]

				Strategic supplier market share		
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	5500	5467	5440	5384	5274	5000
Kinked demand curve	5500	5467	5440	5384	5151	5000

Capacity Supply 112% of ICAP Requirement

With supply equal to 112% of the ICAP requirement, there is no market share level at which the strategic supplier would clear all capacity under either of the demand curves.

As with supply equal to 110% of the ICAP requirement, the most profitable price to offer (and associated amount of capacity) to clear diverges between the kinked and standard demand curves for strategic suppliers having between 6% and 10% market share[72] so that there is more withholding under the kinked demand curve by a strategic supplier with a 10% market share, as shown in Table 20. However, because of the large amount of excess supply, the clearing price is on the lower segment of the kinked demand curve for market shares up to and at 6%. The kinked demand curve is flatter than the standard demand curve in this region, but the price is also lower. Hence, while the decline in marginal revenue is lower, the clearing price is also lower. At a 10% market share and above, it is profitable for the strategic supplier to economically withhold enough supply for the market to clear on the steeper portion of the kinked demand curve above the kink.

While in previous examples consumer payments based on the kinked demand curve exceed those for the standard demand curve between 6% and 10% of market share of the strategic supplier, in this example this does not occur until the market share of the strategic supplier rises to between 10% and 20%. At 10% market share, the market clears on the steeper segment of the demand curve for the kinked demand curve (total cleared quantity < 105% of the ICAP requirement) but due to the large difference between the prices determined by the demand curves the capacity price (and thus consumer payments as well) is higher under the standard demand curve.

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[72] 9%.

In this case, consumer payments are higher under the kinked demand curve when the strategic supplier has a 20% market share. This is different from prior cases. With the kinked demand curve, 5000 MW is cleared which is at the ICAP requirement and is slightly lower than the amount cleared with the standard demand curve (5040 MW). The difference in incentives is due to the steeper slope of the kinked demand curve, which would result in a price of $8.87/kW at 5040MW. The kink in the demand curve, leading a steeper reduction in marginal revenue with more quantity cleared, causes the strategic supplier to set its offer price to clear a slightly smaller output with the kinked demand curve.

Figure 19: Consumer payments with capacity supply equal to 112% of ICAP requirement

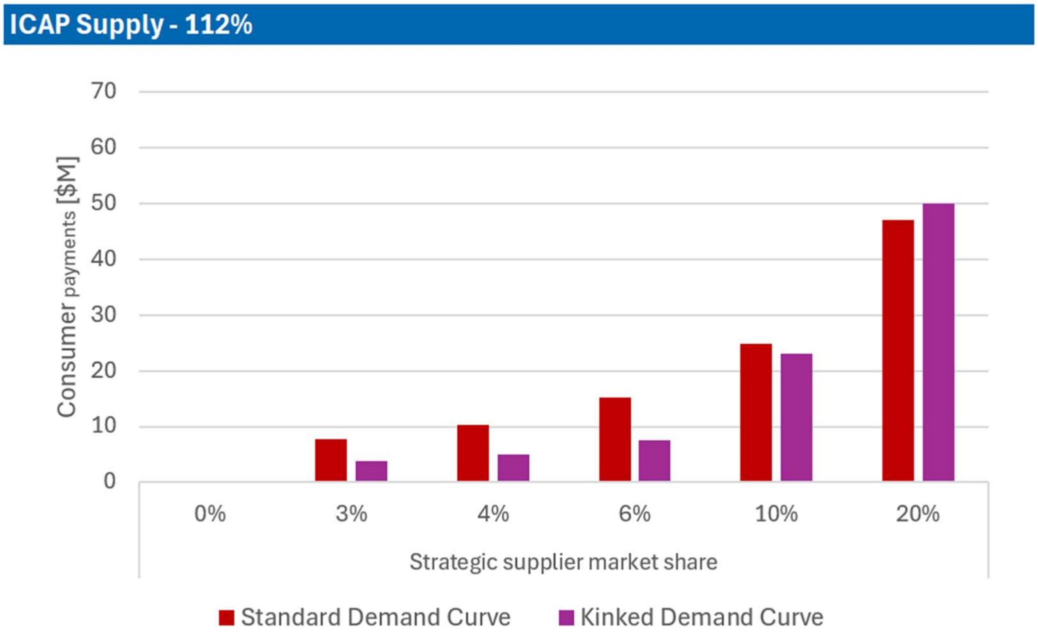

Table 20: Clearing prices and quantities with capacity supply equal to 112% of ICAP requirement

Clearing price [$/kW]

	Strategic supplier market share					
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	0.0	1.4	1.9	2.8	4.7	9.3
Kinked demand curve	0.0	0.7	0.9	1.4	4.4	10.0

Total Cleared quantity [MW]

	Strategic supplier market share					
	0%	**3%**	**4%**	**6%**	**10%**	**20%**
Standard demand curve	0	5515	5488	5431	5319	5040
Kinked demand curve	0	5515	5488	5431	5196	5000

Outcomes with market power mitigation

Introduction

The NYISO tariff provides for offer price mitigation to be applied in the spot auction to the offers of capacity market suppliers that are determined to have market power based on a pivotal supplier test. We will show below that the scenarios in which the kinked demand curve could incent economic withholding of capacity and result in higher consumer costs are mostly scenarios in which the strategic supplier would be subject to market power mitigation based on a pivotal supplier test. When account is taken of the NYISO market power mitigation design, consumer costs are almost always lower with the kinked demand curve. The exceptions appear to be in scenarios in which the strategic supplier is not pivotal but is very nearly pivotal, such as the case with 10% excess supply and a strategic supplier with a 10% market share.

We think further analysis of these nearly pivotal cases would be useful in refining the kinked demand curve concept.

Pivotal Suppliers

Pivotal suppliers in the capacity market are subject to offer price mitigation under the NYISO tariff. The MST, Att. H, Sec 23.2.1 defines Pivotal Suppliers as follows

i. *for the New York City Locality, a Market Party that, together with any of its Affiliated Entities,*
    a) *Controls 500 MW or more of Unforced Capacity, and*
    b) *Controls Unforced Capacity some portion of which is necessary to meet the New York City Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction.*

ii. *for the G-J Locality, a Market Party that, together with any of its Affiliated Entities,*
    a) *Controls 650 MW or more of Unforced Capacity, and*
    b) *Controls Unforced Capacity some portion of which is necessary to meet the G-J Locality Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction.*

In our example we focus on condition b) because the zonal example used to illustrate outcomes does not correspond exactly to Zone J or GHIJ. Hence, we assume that a strategic supplier is classified as pivotal if some portion of its capacity is required to meet the target capacity. The analysis could be extended to include a lower MW threshold and the example could also be recast to more closely correspond to Zone J quantities. We interpret this condition to hold if the total supply minus the supply of the strategic supplier is lower than the ICAP requirement, i.e. if the fringe supply is less than the ICAP requirement.[73]

Table 21 shows the consumer costs for both demand curves for alternative supply balances and supplier market shares. The table also identifies 12 scenarios in which the strategic supplier would be determined to be pivotal under the criterion above. Consumer payments are lower based on the kinked demand curve than

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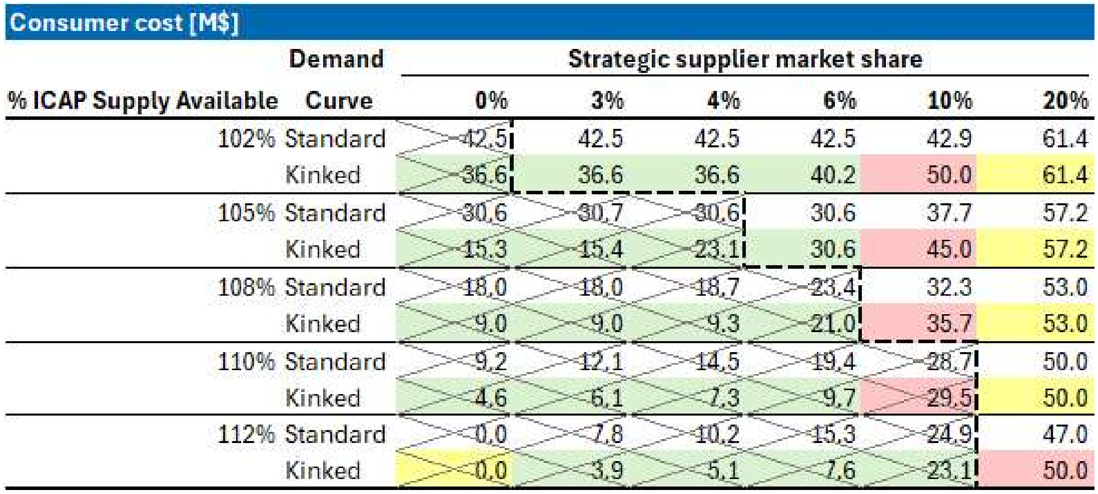
[73] The current G-J Locality and Zone J have a UCAP requirements of 11,191.6 MW and 8,191.1 MW, implying that 650 MW and 500 MW represents 5.8% and 6.1% of the UCAP requirement, respectively. See ICAP Translation of Demand Curve (Summer 2025).

based on the standard demand curve in all but one case in which no supplier is determined to be pivotal. The exception is the case of a strategic supplier with a 10% market share and, ICAP Supply Available is 110% of the requirement.[74] In that case consumer payments are $800,000 higher for a kinked demand curve.

Table 21: Consumer Costs: Demand Curves and Pivotal Suppliers [75]



Consumer cost [M$]

% ICAP Supply Available	Demand Curve	Strategic supplier market share 0%	3%	4%	6%	10%	20%
102%	Standard	42.5	42.5	42.5	42.5	42.9	61.4
	Kinked	36.6	36.6	36.6	40.2	50.0	61.4
105%	Standard	30.6	30.7	30.6	30.6	37.7	57.2
	Kinked	15.3	15.4	23.1	30.6	45.0	57.2
108%	Standard	18.0	18.0	18.7	23.4	32.3	53.0
	Kinked	9.0	9.0	9.3	21.0	35.7	53.0
110%	Standard	9.2	12.1	14.5	19.4	28.7	50.0
	Kinked	4.6	6.1	7.3	9.7	29.5	50.0
112%	Standard	0.0	7.8	10.2	15.3	24.9	47.0
	Kinked	0.0	3.9	5.1	7.6	23.1	50.0

Legend

🟩 Kinked demand curve produces consumer costs that are lower than the standard demand curve

🟥 Kinked demand curve produces consumer costs that are higher than the standard demand curve

🟨 Kinked demand curve produces consumer costs that are the same as the standard demand curve

⬚ Scenarios in which an offer cap would be applied to strategic supplier

☒ Scenarios in which the strategic supplier would not be considered pivotal

Offer Price Cap

Pivotal Suppliers are subject to offer price caps set at the higher of the UCAP Offer Reference Level or its going forward costs. The MST, Att. H, Sec 23.4.5.2 specifies the offer cap in the ICAP market as:

> *"Offers to sell Mitigated UCAP in an ICAP Spot Market Auction shall not be higher than the higher of (a) the UCAP Offer Reference Level for the applicable ICAP Spot Market Auction, or (b) the Going-Forward Costs of the Installed Capacity Supplier supplying the Mitigated UCAP."*

The UCAP Offer Reference Level is defined in Section 23.2.1 as *"…a dollar value equal to the projected clearing price for each ICAP Spot Market Auction determined by the ISO on the basis of the applicable*

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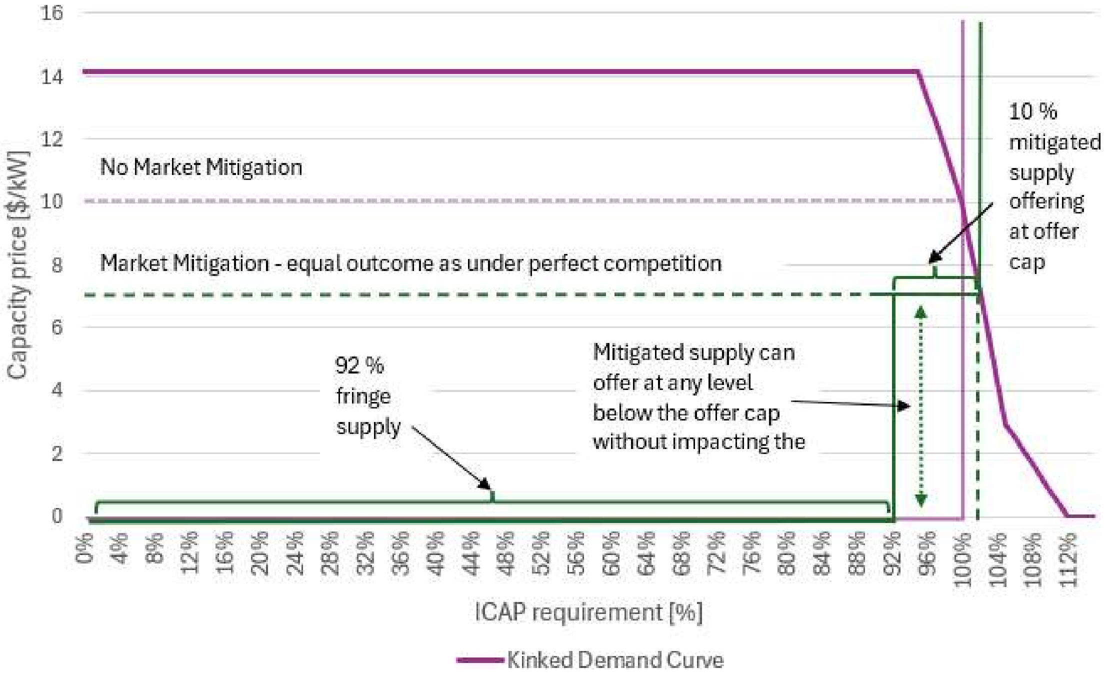
[74] The effect of a minimum capacity requirement in megawatts to the pivotal supplier test (e.g., 500 MW for the NY locality as described above) in addition to the requirement for the supply of the strategic supplier being needed to reach the ICAP requirement would be to remove mitigation for some of the cases with tight supply and low strategic supplier market shares.

[75] From NYISO MST, Att. H, Sec 23.2.1, criteria b refers to "*Controls Unforced Capacity some portion of which is necessary to meet the […] Locational Minimum Installed Capacity Requirement in an ICAP Spot Market Auction*".

ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in a Mitigated Capacity Zone…"

Because supply offered at a price equal to the resource's going forward costs would be offered competitively, we focus on the case in which the offers of the pivotal supplier would be mitigated based on the UCAP Offer Reference Level. With this offer price cap applied, this implies when the capacity of a pivotal supplier is subject to the offer price cap, the outcome will be the same as under perfect competition (market share = 0% in our tables). An illustration of market outcomes with an offer price cap in place for a strategic supplier with 10% market share, 102% total supply of the ICAP requirement available, and a kinked demand curve is shown in Figure 22. In that figure it is assumed that the strategic supplier would offer all its mitigated capacity at the offer price cap level. However, the strategic supplier could equally offer its capacity at any price between zero and the offer price cap level without impacting the clearing price of the capacity auction.

Figure 22: Capacity Prices with and without market mitigation - kinked demand curve, supply 102% of the ICAP requirement and strategic supplier with 10% market share



In Table 23 we show the consumer payments for the different cases with market mitigation in place. As in Table 21, a supplier is considered pivotal for the purpose of mitigation if its supply is needed to meet the ICAP requirement. With market power mitigation in place there is only one case under which the consumer costs are higher with a kinked demand curve. There are some cases where no market power mitigation is applied and there is some amount of economic withholding, however in those cases the impact of economic withholding on consumer cost is small and its impact on consumer costs less with the kinked demand curve.[76]

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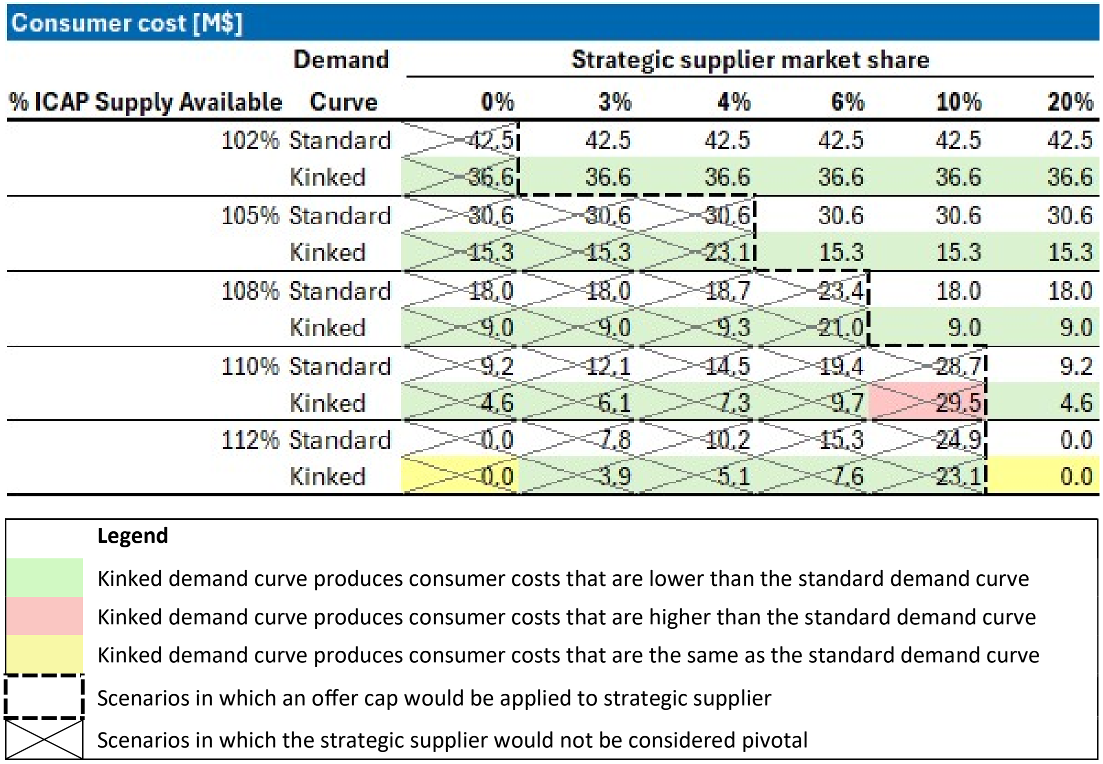
[76] 105% supply and 4% market share for the Kinked Demand Curve, 108% of supply and 4% market share for both curves, 110% supply and 3%/4% of market share for both curves and 110% supply and 3%/4% of market share for both curves.

Table 23: Consumer costs under both demand curves – scenarios where an offer price cap would be applied to the strategic suppliers are indicated by the dotted lines



Consumer cost [M$]

% ICAP Supply Available	Demand Curve	Strategic supplier market share 0%	3%	4%	6%	10%	20%
102%	Standard	42.5	42.5	42.5	42.5	42.5	42.5
	Kinked	36.6	36.6	36.6	36.6	36.6	36.6
105%	Standard	30.6	30.6	30.6	30.6	30.6	30.6
	Kinked	15.3	15.3	23.1	15.3	15.3	15.3
108%	Standard	18.0	18.0	18.7	23.4	18.0	18.0
	Kinked	9.0	9.0	9.3	21.0	9.0	9.0
110%	Standard	9.2	12.1	14.5	19.4	28.7	9.2
	Kinked	4.6	6.1	7.3	9.7	29.5	4.6
112%	Standard	0.0	7.8	10.2	15.3	24.9	0.0
	Kinked	0.0	3.9	5.1	7.6	23.1	0.0

	Legend
🟩	Kinked demand curve produces consumer costs that are lower than the standard demand curve
🟥	Kinked demand curve produces consumer costs that are higher than the standard demand curve
🟨	Kinked demand curve produces consumer costs that are the same as the standard demand curve
⬚	Scenarios in which an offer cap would be applied to strategic supplier
☒	Scenarios in which the strategic supplier would not be considered pivotal

Marginal Reliability Based Demand Curve

Another type of demand curve would be one based on estimates of the marginal reliability improvement (MRI) of incremental capacity. Our understanding is that the MRI curve would be calculated by measuring the change in loss of load probability from each increment of capacity added to the system above the minimum capacity requirement. To convert the change in loss of load probability to a monetary value, each MRI value on the curve would be multiplied by a dollar value of incremental reliability. The value of the scaling factor could be set to ensure that the peaking unit underlying each ICAP Demand Curve would be revenue sufficient if it entered the market to prevent a reliability shortfall.[77] This approach would avoid the need to calculate the value of lost load, the demand curve would be still be anchored by net CONE.

Rather than a linear demand curve with kinks, an MRI demand curve could in principle be a smooth curve as portrayed in Figure 24. Figure 24 focuses on the demand curve region with excess supply but could be extended to cover capacity shortages.

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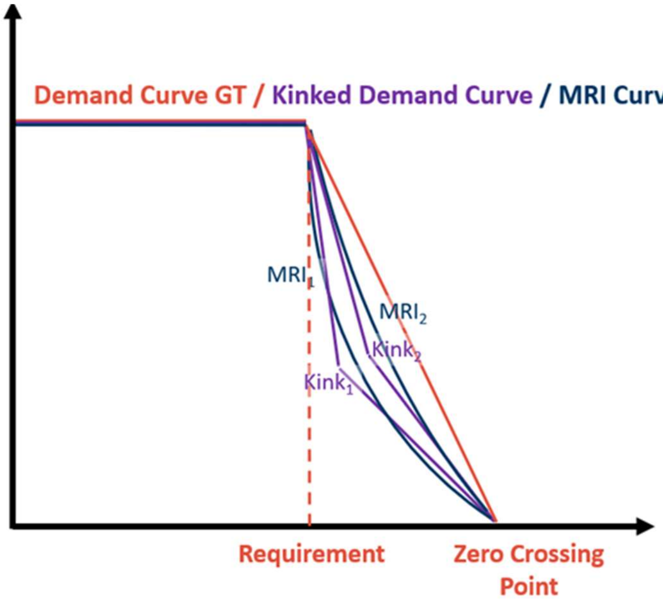
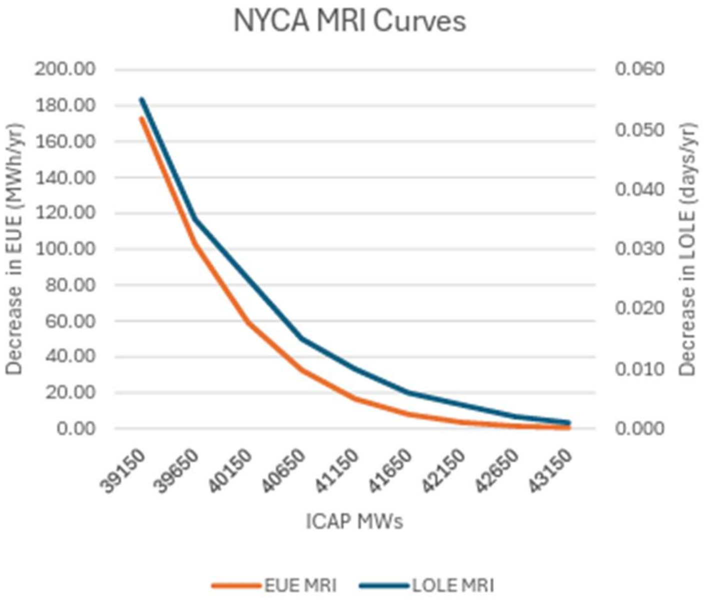
[77] This corresponds to the method described in Maddy Mohrman, NYISO, “Capacity Market Structure Review; ICAP Demand Curve Resent Process and Methodology Improvements,” ICAPWG? MIWG May 22, 2025 p. 26.

Figure 24: Example MRI Demand Curves 1 and 2



How smooth an MRI curve would be in practice would depend on how it was constructed. The MRI curve calculated from MRI values calculated for just a few capacity levels would be a kinked curve, but with more kinks than the kinked demand curve analyzed in Sections II, III and IV. Such a multi-kink MRI curve is illustrated in Figure 25 below, from the May 22, 2025 NYISO presentation.

Figure 25: Example MRI Curves from NYISO presentation[78]



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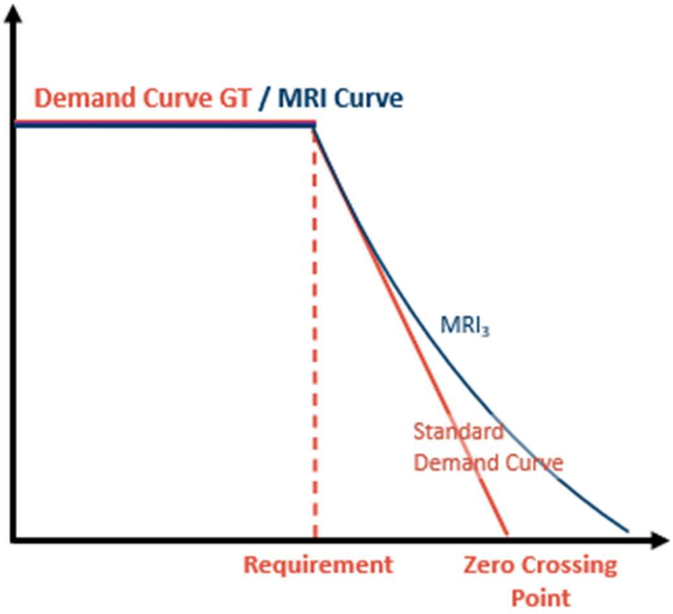
[78] "Capacity Market Structure Review; ICAP Demand Curve Resent Process and Methodology Improvements," ICAPWG? MIWG May 22, 2025 p. 28.

An MRI based demand curve would not necessarily be steeper than the standard demand curve in any particular region; this would be an empirical matter based on the change in reliability as capacity increases. The case in which the reliability value of capacity declines even less rapidly than with the standard demand curve is illustrated in Figure 26, which is also truncated to only show the demand curve region with capacity surpluses.

Figure 26: Example MRI Demand Curve 3



In practice, we expect that diminishing reliability returns to incremental capacity would cause an MRI curve and MRI demand curve to be convex, but this might not be true in all regions.

If an MRI demand curve were steeper than the standard demand curve or the kinked demand curve analyzed in Sections II, III and IV, such as a demand curve based on the NYCA MRI curve in Figure 25, this steeper demand curve would tend to incent more economic withholding of capacity for a strategic supplier with a given share of market capacity in the region of small capacity surplus in which the MRI demand curve is steeper than the kinked demand curve. However, we have seen in Section IV that it is in this range of small capacity surpluses that capacity sellers in zones J, and GHIJ are very likely to be mitigated because in that case the capacity of the pivotal supplier is likely required to meet the capacity requirement and mitigation is triggered. Hence, it is not necessarily the case that an MRI based demand cure would enable more exercise of unmitigated market power than either the standard demand curve or the kinked demand curve analyzed in Sections II, III and IV.

The conceptual approach of basing the demand curve shape on changes in reliability is reasonable. However, this approach makes it very important that the NYISO correctly measure the value of incremental reliability. One consideration from this perspective is the degree to which the LOLE analysis accurately reflects the incremental loss of load value of incremental capacity. One caveat the NYISO is familiar with is that the conventional LOLE analysis does not account for most transmission outages, which is therefore separately modeled as transmission security requirements. The current 1 in 10 year standard can be thought of defining the capacity level needed to provide about the same level of capacity as in prior years, but not the actual reliability level.

A second consideration is one FTI has raised with the NYISO a number of times over the years in a variety of contexts. NYISO reserve requirements are not determined by NYISO based on reducing NYISO loss of load expectation. They are imposed on NYISO by NPCC and NERC, presumably because of the external effects of a lack of reserves. From this perspective, perhaps we should also consider a reliability measure that includes external impacts, such as the number of days the NYISO would operate in a state of emergency in the LOLE model, either for NYCA or east of central east. This curve might be different from the LOLE curve that assumes there is no problem until there is load shedding.

Preliminary conclusions

While the use of a kinked demand curve in the capacity market spot auction would incent greater economic withholding than the standard demand curve in some scenarios, these are generally scenarios in which the supplier would be identified as pivotal and subject to mitigation (based on our understanding of the pivotal supplier test). When account is taken of mitigation, consumer costs based on the kinked demand curve analyzed in this note would almost always be lower than or equal to consumer costs based on the standard demand curve.

This note describes a first step analysis intended to illustrate the basic principles. The results have been developed for a particular kinked demand curve, a demand curve with an upper kink at 100% and a lower kink 105% of the ICAP requirement and the demand curve below the lower kink being the same as a demand curve anchored by the going forward costs of a GT. Varying either of these parameters would result in somewhat different results.

If we hold the price at the lower kink constant and reduce the excess supply percentage at the lower kink (i.e. lower than 5% in our example), the middle segment of the kinked demand curve will become even steeper. This would increase the incentive of a strategic supplier to economically withhold supply, but the region above the lower kink would involve small excess supply so would correspond to cases in which even suppliers with small shares would be mitigated. Hence, if the lower kink were at 3% excess supply, then all suppliers with a market share in excess of 3% would be mitigated in this range. For outcomes below the lower kink, the flatter slope would reduce the incentive to exercise market power.

If we hold the excess supply percentage constant for the kink location but lower the price at the kink, this would make the demand curve steeper for supply below the kink and potentially increase the incentive to exercise market power by economically withholding output. On the other hand, prices would be even lower for a kinked demand curve with the kink at a lower price.

- A limitation of the pivotal supplier analysis in this paper is that we only considered cases with one pivotal supplier. Cases with multiple suppliers with material market shares might be more accurate but would be much more complex to analyze. There is considerable theoretical and empirical ambiguity in solving such models. Hence, we believe the single pivotal supplier case is a reasonable starting point.
- Another simplification in the examples is that they do not apply well to zones with nested supply such as GHIJ and NYCA. Hence, the examples apply best to Zone J. However, we think that the conclusions

would generally extend to zones GHIJ and NYCA with market shares defined based on capacity cleared at the GHIJ and NYCA prices.

- A final simplification is that the examples assume that the supply cost of both fringe and strategic supplier capacity is zero. This assumption is appropriate in the context of single monthly spot auction but is not valid longer term as more supply would exit the market at lower clearing prices, making supply dependent on clearing prices in the long-run.

Elaborating on the last point, a long run impact of a kinked demand curve is that more fringe supply would exit at high levels of surplus because of the lower capacity price. This exit would tend to increase capacity prices over time. However, when supply falls to a level above the lower kink, the clearing price would rise rapidly with further exit, which would tend to keep needed capacity in operation.

While a kinked demand curve, or a demand curve anchored by going forward costs, would reduce consumer costs in the short-term, if the lower price led to the exit of a material amount of fringe supply, capacity prices would rise. We think it is important to recognize that both the standard demand curve and the kinked demand curve have the property that total consumer payments decline with higher levels of capacity. Even though more capacity is purchased as supply rises above the ICAP requirement, the clearing price falls much more than the increase in capacity purchases. Thus, with a 112% zero crossing point and the standard demand curve, the purchase of 3% more capacity would be associated with a 25% reduction in the capacity price. Total consumer payments would be more than 20% lower with a 3% surplus than with capacity at requirements. This pattern of declining capacity costs can be clearly seen in Table 5. From this perspective it is financially beneficial to consumers to retain a capacity surplus, in addition to the reliability benefits.

From this perspective a consideration in setting the quantity kink, and the price at the quantity kink would be the amount of excess capacity the NYISO would feel comfortable with from an operational standpoint. We understand that more capacity is always better from a reliability standpoint, but at what level of excess is the marginal reliability value very low. This relates back to the point that we made that ideally from an efficiency standpoint the demand curve would reflect the marginal reliability value of capacity. If that were the case, the price paid for capacity would equal its reliability value to consumers. However, that reliability value is hard to set not only in terms of estimating outage probabilities but also specifying the value of lost load. Moreover, as we have noted in prior discussions, part of the value of incremental capacity is to reduce the likelihood of outages that extend outside the NYISO footprint.

In a competitive capacity market with entry driven by market prices, existing capacity should remain in operation, making staying in business investments based on expected future capacity prices, with expected future capacity prices driven by expected load growth, entry, exit and fuel price changes, as well as by the risks associated with differences between actual and expected future prices. With the expected dominant role of state subsidies and procurement in determining the level of new entry in NYISO markets, the expectations of existing resources regarding future prices will be materially impacted by expectations regarding state procurement. However, because state procurement is not driven by economics, it may be low when capacity prices are high and high when capacity prices are low.

The unpredictability of future subsidized procurement can create more uncertainty and risk for existing generators in making staying in business investment decisions. This is something to have in mind in assessing the merits of the shape of the demand curve for larger surpluses, particularly if the level of surplus may only amount to two or three years of load growth, in which case the capacity surplus would provide a cushion for delays in the entry of new capacity and would have more value than measured by a static LOLE calculation.

Concave Kinked Demand Curve Concept

Scott Harvey, Tim Schittekatte and Victoria Lorvig

September 16, 2025

I. Introduction

FTI has been working with NYISO to discuss potential changes to the slope and shape of the demand curve used to clear ICAP auctions. Recent discussions with the NYISO indicate concerns that the steepness of the current curve – particularly in the NYC locality – leads to volatile capacity market prices. This is because with a steep demand curve, minor entry or exit decisions can have a profound impact on the capacity market clearing prices, which is amplified in small zones.

Previous FTI notes[79] have discussed a variety of changes to the shape of the capacity market, including cases of convex kinked and marginal reliability impact (MRI) demand curves for NYCA. In this note we discuss changes to the shape of the current NYC demand curve that would produce a concave capacity market demand curve for the zone by breaking the demand curve into two segments. These sections' individual slopes would be determined so that the demand curve would have the same reference price and zero crossing point as the current demand curve.

As illustrated in *Figure 16*, the "top segment" of the demand curve would have a slope that passes through both the designated "kink point" and the reference price, while the "bottom segment" passes through the kink point and the zero-crossing point. Designation of the kink point, both its price and position (i.e. level of excess), is the element of design that differs from current demand curve parameters.[80]

The choice of the two additional parameters allows a wide variety of demand curve shapes and outcomes. Moving the kink price up, reduces the slope of the left segment of the demand curve and raises the price. Moving the kink quantity to the right reduces the slope and increases the range of higher prices. For example, the red dashed line in *Figure 16* shows a demand curve with a $18.29 * 120% = $21.94 kink price, with the kink price assumed to be 1.2x of the clearing price under the current demand curve at the point on the demand curve with a 6% capacity surplus.

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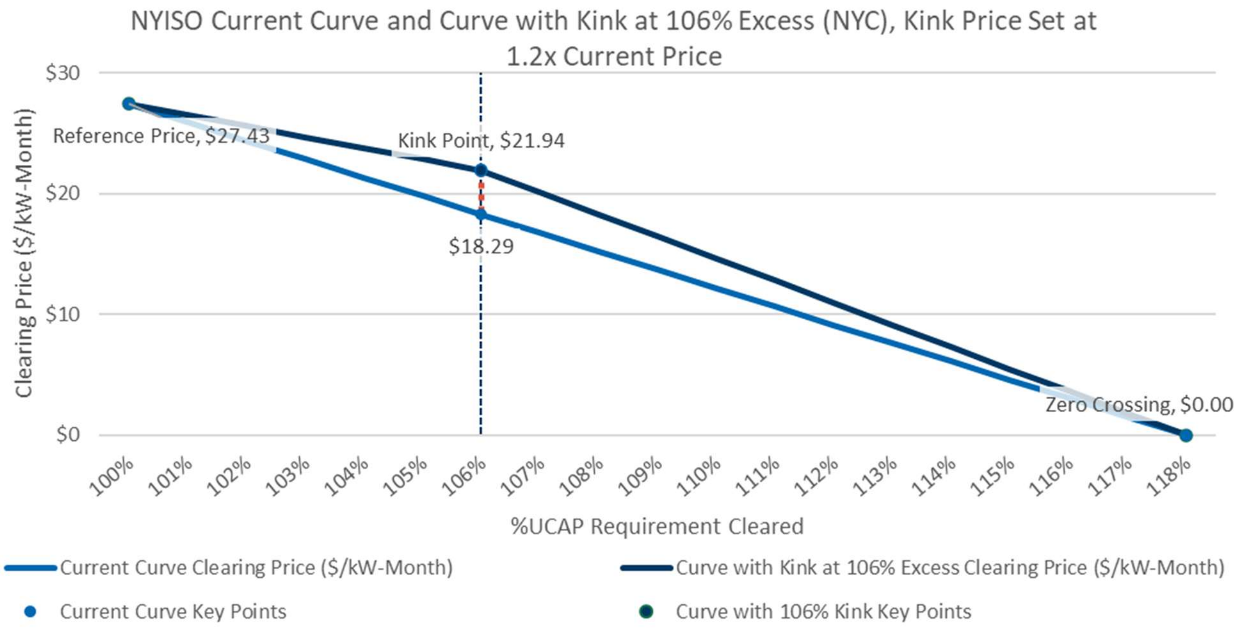
[79] See Scott Harvey, Tim Schittekatte and Victoria Lorvig, "Potential for Market Power Issues with a Kinked Demand Curve", August 6, 2025 (revised draft August 19, 2025).

[80] The choice of maximum price can also be chosen to deviate from the established demand curve parameters, but changes to the demand curve anchor are not the focus of this memo.

Figure 16: Example Concave Kinked Curve



In the example above, the location of the kink is at 106% of excess cleared capacity and the price at the kink point is set equal to 120% of the clearing price of the current demand curve at that level of excess demand. Setting the price of the kink point higher than the clearing price of the current demand curve at the same level of excess demand leads to a concave demand curve (and, vice versa, setting the kink point price lower than the current demand curve leads to a convex demand curve). The features and flexibility of this design are illustrated in Section II, detailed examples. In Section III, Further Discussion, we illustrate how alterations to adjustments to the parameters can yield a variety of demand curve outcomes.

II. Detailed Examples

To start, we provide examples of kink points at 106% and 109% levels of excess capacity.[81] Similar to the choice of kink price, this level of excess is simply used to develop illustrative outcomes based on the general concept. The parameters can easily be adjusted to yield additional outcomes. The price at the kink can be adjusted to be set at different price levels and at different levels of capacity excess.

Detailed tables showing the data used to create these graphics are provided in **Appendix: Detailed Tables**.

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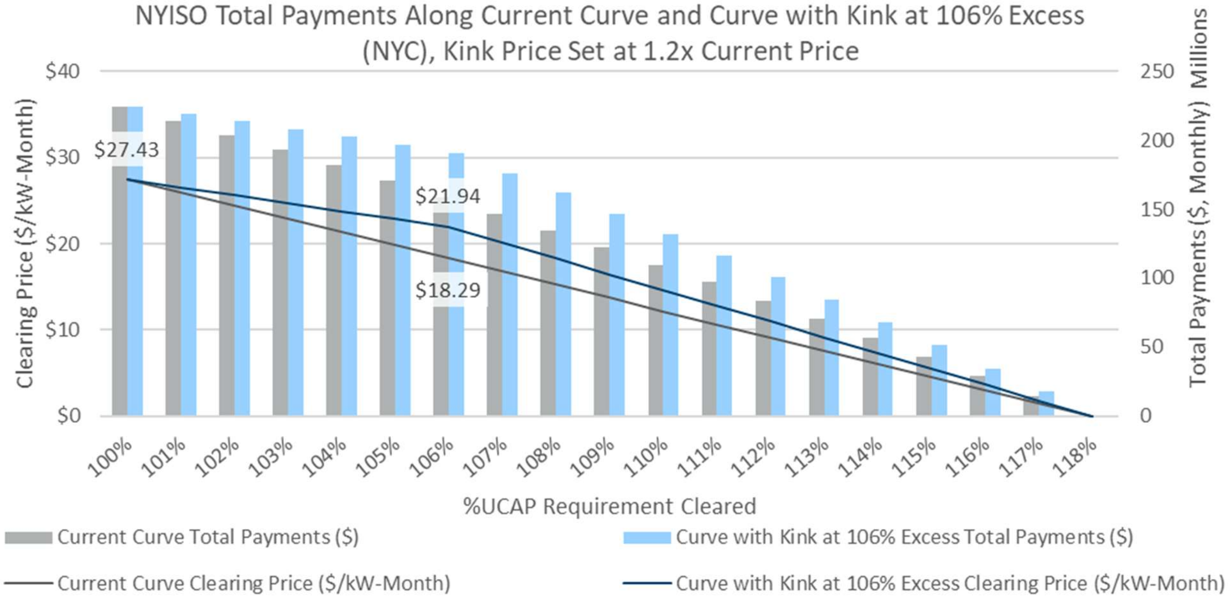
[81] Note that in "Potential for Market Power Issues with a Kinked Demand Curve", we used a single curve with kinks at 100% and 105%. In that same note we only considered convex kinked demand curves.

Kink at 106%

Our first example, shown in *Figure 17*, portrays both capacity prices and total load payments for different levels of surplus for both the current NYC demand curve, and the illustrative kinked curve with the kink placed at 106% of UCAP requirement and the price at the kink point set equal to 120% of the clearing price on the current demand curve at that level of excess capacity. As seen in the increasing difference between the blue and gray bars, total payments under the kinked curve fall somewhat more slowly than under the current curve up to the 106% kink, then fall more rapidly to match payment levels under the current demand curve at the 118% zero crossing point.

Figure 17: Total payments for different clearing prices of both the current and kinked demand curve

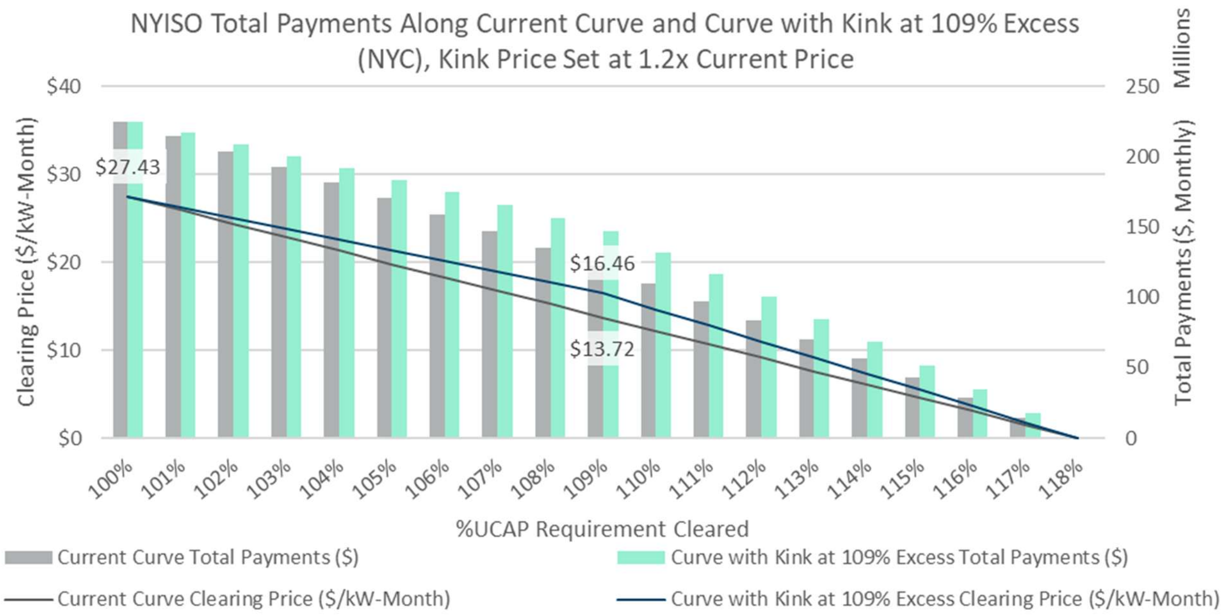


For capacity levels in excess of the UCAP requirement, the kinked curve provides overall higher prices and higher payments by load than the current demand curve, but the overall capacity payment cost to load is still declining with increasing levels of capacity surplus. This reflects the fact that the kinked demand curve places a higher value on excess capacity without raising the reference price or length of the demand curve. This will be the case as long as the price at the kink is lower than the reference price.

Kink at 109%

Figure 18 shows what happens if the kink point is pushed out to 109% of the UCAP requirement, while continuing to assume the price at the kink is 1.2x that of the clearing price on the current NYC demand curve (the same ratio as in the 106% example above). We have a similar price at the kink point of 109% excess than with the kind at 106% but a steeper slope for the “top segment” of the demand curve. This steeper slope causes a steeper decline in total payments for the kinked demand curve for low surplus values than the kink point at 106% excess demand and results in smaller differences between the current and the kinked curve prices and payments.

Figure 18: Total payments along different clearing prices of both the current and kinked demand curve

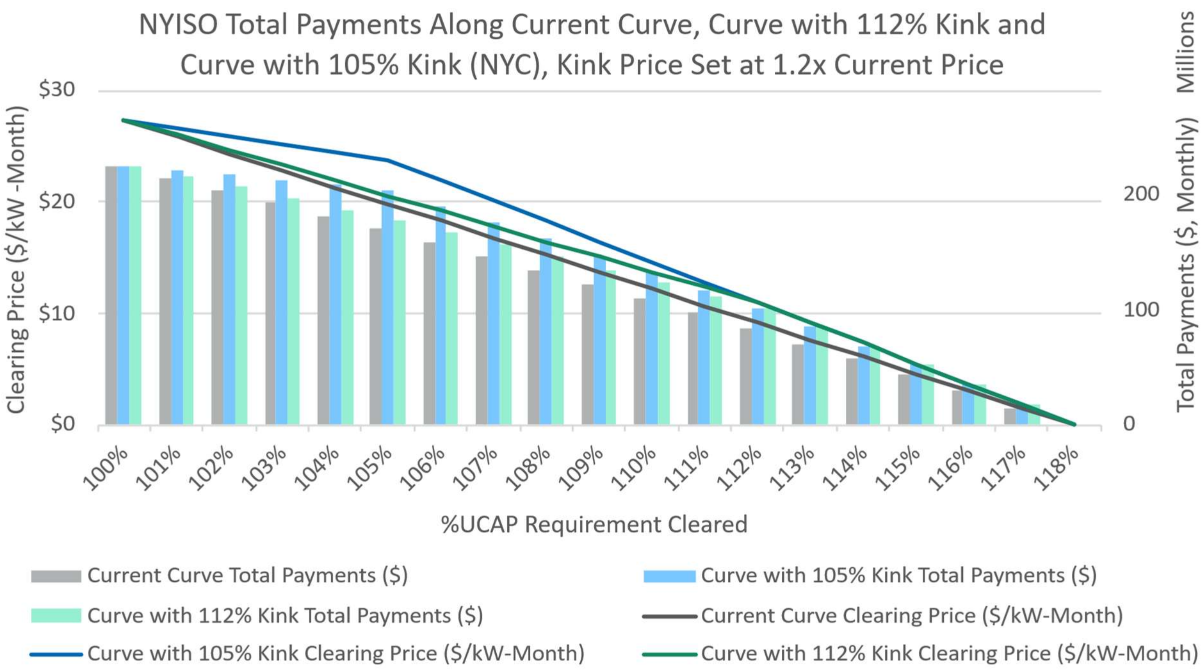


III. Further Discussion

To understand the full flexibility provided by this type of demand curve design, more variations in the placement of the kink could be examined. A kink at 106% of reference (one third excess capacity relative to the zero-crossing point) or at 109% of reference (halfway to the zero crossing point) are just illustrative starting points. Many other options are possible. The price point of the kink relative the clearing price of the current demand curve can also be adjusted to make the curve more or less concave.

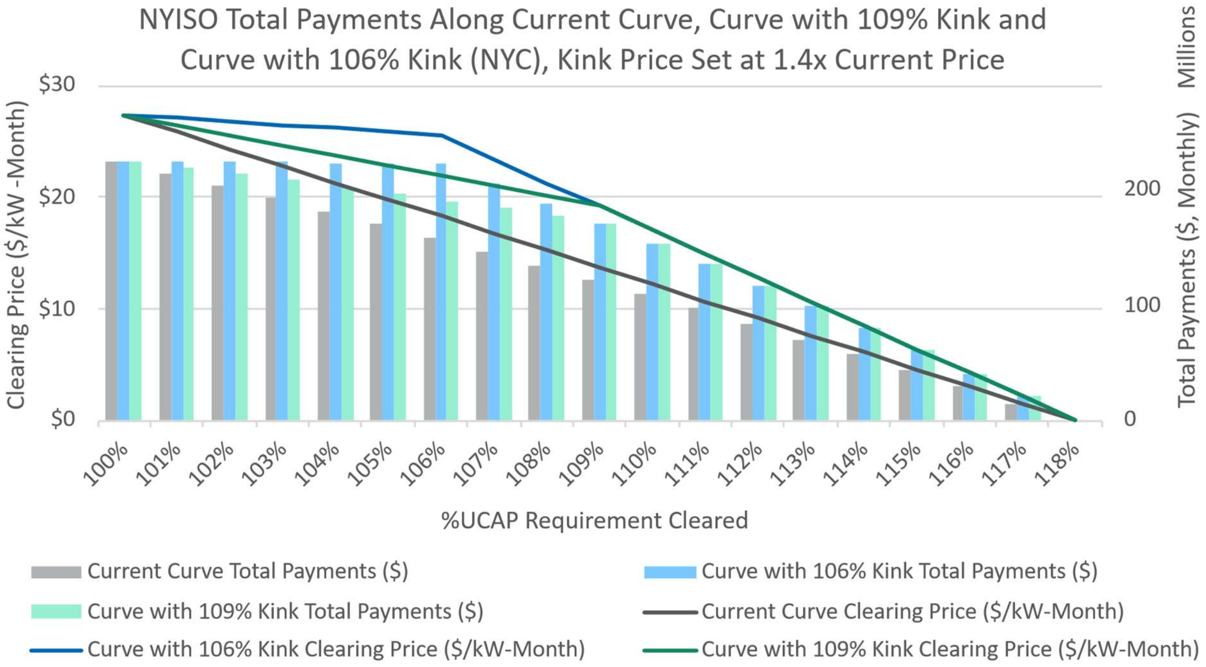
For example, if we slightly decreased the excess supply at the kink location to 105% and kept a 1.2x scaling factor for the kink price, capacity prices would again be higher relative to the current demand curve. Capacity prices and consumer payments would also be higher relative to a demand curve with a kink at 112% for cleared capacity out to the kink as shown in *Figure 19*. However, capacity prices and consumer payments would be the same for demand curves with a kink at 105% and 112% for cleared capacities of 112% or more.

Figure 19: Total payments current and kinked demand curves with increased higher and lower kinks



The other factor to be considered is the kink price. For example, if the price at the kink were raised to 1.4x the current price at 6% excess capacity as shown in Figure 5, we would see practically flat total payments for cleared capacity up to the 106% kink, and higher overall payments for kinked demand curves with kinds at either 10^% or 109% compared to the current demand curve shape. It can also be seen that the slope, and total payments, are the same for kinked curves with a kink at either 106% or 109% once the cleared quantity exceeds the level excess at both kinks (106% and 109%).

Figure 20:Total payments current and kinked demand curves with higher kink price



Appendix: Detailed Tables

		Current Curve			Curve with Kink at 106% Excess and 1.2x Clearing Price			Curve with Kink at 109% Excess and 1.2x Clearing Price		
UCAP Req.	Quantity Cleared	Clearing Price	Total Payments	Change in Total payments	Clearing Price	Total Payments	Change in Total payments	Clearing Price	Total Payments	Change in Total payments
(%)	(MW)	($/kW-Month)	($)	($)	($/kW-Month)	($)	($)	($/kW-Month)	($)	($)
100%	**8,191**	**$27.43**	**224,681,873**	**-10,110,684**	**$27.43**	**224,681,873**	**-5,167,683**	**$27.43**	**224,681,873**	**-7,639,184**
101%	8,273	$25.91	214,321,542	-10,360,331	$26.52	219,364,402	-5,317,471	$26.21	216,842,972	-7,838,901
102%	8,355	$24.38	203,711,565	-10,609,977	$25.60	213,897,143	-5,467,259	$24.99	208,804,354	-8,038,618
103%	8,437	$22.86	192,851,941	-10,859,624	$24.69	208,280,096	-5,617,047	$23.77	200,566,019	-8,238,335
104%	8,519	$21.33	181,742,671	-11,109,270	$23.77	202,513,262	-5,766,835	$22.55	192,127,966	-8,438,053
105%	8,601	$19.81	170,383,754	-11,358,917	$22.86	196,596,639	-5,916,623	$21.33	183,490,196	-8,637,770
106%	**8,683**	**$18.29**	**158,775,190**	**-11,608,563**	**$21.94**	**190,530,228**	**-6,066,411**	$20.12	174,652,709	-8,837,487
107%	8,764	$16.76	146,916,980	-11,858,210	$20.12	176,300,376	-14,229,852	$18.90	165,615,505	-9,037,204
108%	8,846	$15.24	134,809,124	-12,107,856	$18.29	161,770,949	-14,529,428	$17.68	156,378,584	-9,236,921
109%	**8,928**	**$13.72**	**122,451,621**	**-12,357,503**	$16.46	146,941,945	-14,829,004	**$16.46**	**146,941,945**	**-9,436,639**
110%	9,010	$12.19	109,844,471	-12,607,150	$14.63	131,813,365	-15,128,579	$14.63	131,813,365	-15,128,579
111%	9,092	$10.67	96,987,675	-12,856,796	$12.80	116,385,210	-15,428,155	$12.80	116,385,210	-15,428,155
112%	9,174	$9.14	83,881,233	-13,106,443	$10.97	100,657,479	-15,727,731	$10.97	100,657,479	-15,727,731
113%	9,256	$7.62	70,525,143	-13,356,089	$9.14	84,630,172	-16,027,307	$9.14	84,630,172	-16,027,307
114%	9,338	$6.10	56,919,408	-13,605,736	$7.31	68,303,289	-16,326,883	$7.31	68,303,289	-16,326,883
115%	9,420	$4.57	43,064,026	-13,855,382	$5.49	51,676,831	-16,626,459	$5.49	51,676,831	-16,626,459
116%	9,502	$3.05	28,958,997	-14,105,029	$3.66	34,750,796	-16,926,034	$3.66	34,750,796	-16,926,034
117%	9,584	$1.52	14,604,322	-14,354,675	$1.83	17,525,186	-17,225,610	$1.83	17,525,186	-17,225,610
118%	9,665	$0.00	0	-14,604,322	$0.00	0	-17,525,186	$0.00	0	-17,525,186